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THE UNIVERSITY OF ALBERTA

STUDY OF THE IMMISCIBLE
CARBON DIOXIDE WAG PROCESS
AT LOW PRESSURES

BY

GERALD WILSON PROSPER

A THESIS
SUBMITTED TO THE FACULTY OF GRADUATE STUDIES AND RESEARCH
IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE DEGREE
OF MASTER OF SCIENCE
IN
PETROLEUM ENGINEERING

DEPARTMENT OF MINING, METALLURGICAL AND PETROLEUM
ENGINEERING

EDMONTON, ALBERTA
SPRING, 1992

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To

My Family & Friends

Who

Made It Possible

ABSTRACT

Many heavy oil reservoirs in Alberta and Saskatchewan are unsuitable for thermal recovery methods. The present research was directed towards the development of non-thermal methods for such reservoirs.

The main focus of this research was on the assessment of the recovery mechanisms for the *low pressure* immiscible carbon dioxide water-alternating-gas (WAG) flooding process, employing a linear and a two-dimensional scaled model.

Runs carried out to simulate the Aberfeldy field in a linear model were repeated in a two-dimensional model for the same pressures and WAG ratios, so that the results could be compared. The linear model essentially eliminated sweep effects, so that displacement and mobilization efficiencies could be studied more closely.

The oil recovery in the linear model experiments for operations at 2.5 MPa was approximately 50%. The base recovery by a waterflood was about 40%; hence, the incremental recovery due to the WAG process was approximately 10%. The recovery in the two-dimensional model experiments ranged from 40 to 50%.

Recovery mechanisms were analyzed by evaluating the relative contributions of WAG, the driving waterflood and the blowdown phases of the process. The effect of gas in solution in oil in the carbon dioxide WAG process was examined also.

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TABLE OF CONTENTS

Chapter Page

1. INTRODUCTION 1
2. STATEMENT OF THE PROBLEM 2
3. REVIEW OF THE LITERATURE 3
    3.1 The Miscible Carbon Dioxide Flooding Process 3
    3.2 The Immiscible Carbon Dioxide Flooding Process 4
        3.2.1 Continuous Injection of Carbon Dioxide 4
        3.2.2 Carbonated Waterflooding 5
        3.2.3 Simultaneous Water-Carbon Dioxide Injection Process 5
        3.2.4 Carbon Dioxide Slug Process 5
        3.2.5 Immiscible Carbon Dioxide WAG Process 5
        3.2.6 Carbon Dioxide Huff n' Puff Process 8
    3.3 Carbon Dioxide Properties Which Play a Role in Immiscible Processes 10
        3.3.1 Heavy Oil Properties 11
        3.3.2 Properties of Carbon Dioxide 11
        3.3.3 Transport Properties of Carbon Dioxide in Heavy Oil 12
            3.3.3.1 Solution 12
            3.3.3.2 Diffusion 13
            3.3.3.3 Dispersion 14
        3.3.4 Influence of Carbon Dioxide on Oil, Water and Formation Properties 14
            3.3.4.1 Viscosity Reduction 14
            3.3.4.2 Swelling 16
            3.3.4.3 Effects of Interfacial Tension 16
            3.3.4.4 Effects of Velocity and Temperature 17
            3.3.4.5 Asphaltene Flocculation 17
            3.3.4.6 Mobility Control Agents 18
            3.3.4.7 Blowdown Recovery Mechanism 19
        3.3.5 Other Gases (Nitrogen and Methane) 19
            3.3.5.1 Effect of Nitrogen on Oil Recovery 19
            3.3.5.2 Effect of Methane on Oil Recovery 20
    3.4 Laboratory Studies 20

3.4.1 Physical Model Scaling Methods 22
  3.4.1.1 Dimensional Analysis 22
  3.4.1.2 Inspectional Analysis 22
3.4.2 Laboratory Studies of the Huff n' Puff Process 28
3.4.3 Numerical Simulation Studies of Heavy Oil Production by Carbon Dioxide Injection 33
3.4.4 Immiscible Carbon Dioxide Field Projects 35
  3.4.4.1 Wilmington Project 35
  3.4.4.2 Bati Raman Project 36
  3.4.4.3 Lick Creek Project 36
  3.4.4.4 Hansford Marmation Project 37
  3.4.4.5 Hilly Upland Project 37
3.4.5 Huff n' Puff Field Scale Projects 37
  3.4.5.1 Appalachian Basin 37
  3.4.5.2 Paradis Field 38
4. EXPERIMENTAL APPARATUS and PROCEDURE 39
4.1 Fluids and Porous Medium 39
4.1.1 Fluids 39
  4.1.1.1 Live Oil Sample Preparation 39
4.1.2 Porous Medium 42
4.2 Fluid Injection and Production Systems 42
4.2.1 Fluid Injection 42
4.2.2 Fluid Production 43
4.2.3 Gas Injection 43
4.2.4 Gas Production 43
4.3 Data Acquisition System 44
4.4 Experimental Apparatus and Procedure 44
5. DISCUSSION OF RESULTS 51
5.1 General Description 51
5.2 Presentation of the Experimental Results 56
5.2.1 Two-Dimensional Model Experiments 56
  5.2.1.1 Effect of a Small Carbon Dioxide Volume and a Large WAG Ratio (40:1) 56
  5.2.1.2 Effect of Flow Velocity 58
  5.2.1.3 Effect of Operating Pressure 62
  5.2.1.4 Effect of Slug Size 68

5.2.2 Linear Model Experiments 79
    5.2.2.1 Effect of Slug Size 79
    5.2.2.2 Tertiary Recovery Experiment 91
5.2.3 Live Oil Experiments 93
    5.2.3.1 Tertiary Recovery Experiment Using Live Oil 111
    5.2.3.2 Comparison of Live Oil and Dead Oil Experiments Using Identical Parameters 111
    5.2.3.3 Repeatability of Experiments 115
5.2.4 Effect of Slug Size on the WAG and Total Oil Recoveries 115
5.2.5 Effect of Blowdown on Oil Recovery 123
5.2.6 Effect of Pressure on Carbon Dioxide Retention and Requirement 123
5.3 Comparison of the Present Experimental Results with the Previous Work 126
5.3.1 Experiment Conducted at 2.5 MPa in the Two-Dimensional ..... Model 126
5.3.2 Experiments Conducted at 1.0 and 2.5 MPa in the Linear .... Model 126
6. CONCLUSIONS 136
7. RECOMMENDATIONS FOR FURTHER RESEARCH 138
REFERENCES 139
Appendix A: Density Calculation for the Oil Sample 145
Appendix B: Live Oil Viscosity Calculation 146
Appendix C: Tabulated Data of the Conducted Experiments 149
Appendix D: Production History Figures of the Experiments 200
Appendix E: Oil Recovery Distribution Figures of the Experiments 205
Appendix F: Volumetric Balance Figures of the Experiments 209

LIST OF TABLES

Table Caption Page

3.1. Rock and Fluid Properties of the Prototype 21
3.2. Summary of Previous Immiscible Carbon Dioxide Experiments 29
5.1. Comparison of Results—Two-Dimensional Model Experiments 52
5.2. Comparison of Results— Linear Model Experiments 53
5.3. Linear Model: Live Oil Experiments 54

A1. Tabulated Results of GTD 1. 150
A2. Tabulated Results of GTD 2. 152
A3. Tabulated Results of GTD 3. 154
A4. Tabulated Results of GTD 4. 156
A5. Tabulated Results of GTD 5. 158
A6. Tabulated Results of GTD 6. 160
A7. Tabulated Results of GTD 7. 162
A8. Tabulated Results of GTD 8. 164
A9. Tabulated Results of GTD 9. 166
A10. Tabulated Results of GTD 10. 168

A30. Tabulated Results of LC 30. 170
A31. Tabulated Results of LC 31. 172
A32. Tabulated Results of LC 32. 174
A33. Tabulated Results of LC 33. 176
A34. Tabulated Results of LC 34. 178
A35. Tabulated Results of LC 35. 180
A36. Tabulated Results of LC 36. 182
A37. Tabulated Results of LC 37. 184
A38. Tabulated Results of LC 38. 186
A39. Tabulated Results of LC 39. 188
A40. Tabulated Results of LC 40. 190
A41. Tabulated Results of LC 41. 192
A42. Tabulated Results of LC 42 194
A43. Tabulated Results of LC 43. 196
A44. Tabulated Results of LC 44. 198

LIST OF FIGURES

Figure Caption Page

3.1. Schematic of Carbonated Waterflooding Process ... 6
3.2. Schematic of Simultaneous Water-CO2 Injection Process ... 6
3.3. Schematic of CO2 Slug and Water Drive Process ... 7
3.4. Schematic of Water Alternating Gas (WAG) CO2 Process ... 7
3.5. Cyclic Huff n 'Puff Stimulation Process ... 9
4.1. Schematic of the Physical Model Apparatus ... 40
4.2. Schematic of the Test Oil Saturated with Methane ... 41
4.3. Calculation of the Amount of Brine in Solution for the Two-Dimensional Model ... 46
4.4. Pore Volume Determination for the Two-Dimensional Model ... 46
4.5. Oil Recovery distribution of Run LC 33 ... 48
4.6. Production History Distribution of Run LC 33 ... 50
5.1. Flow Chart of the Experiments Conducted ... 55
5.2. Oil Recovery Distribution of Run GTD 1. ... 57
5.3. Production History of Run GTD 1. ... 59
5.4. Production History of Two-dimensional Model Experiments Injecting 20% HCPV of Carbon Dioxide at Different Operating Pressures and Flow Rates ... 60
5.5. GOR Production History of the Two-Dimensional Model Experiments @ 2.5 MPa, 4:1 WAG, and 10 Slugs ... 61
5.6. GOR Production History of the Two-Dimensional Model Experiments @ 1.0 MPa, 4:1 WAG, and 10 Slugs ... 61
5.7. GOR Production History of the Two-Dimensional Model Experiments @ 1.0 MPa, 4:1 WAG, and 10 Slugs ... 61
5.8. Production History of Run GTD 3 ... 63
5.9. Production History of Run GTD 5 ... 64
5.10. Oil Recovery Distribution of Run GTD 3 ... 65
5.11. Oil Recovery Distribution of Run GTD 5 ... 66
5.12. Two-Dimensional Model Experiment @ 1.0 MPa, 4:1 WAG, 10 Slugs and v=1.3m/d ... 67
5.13. Two-Dimensional Model Experiment @ 1.0 MPa, 4:1 WAG, 10 Slugs and v=2.6m/d.. ... 67

5.14. Two-Dimensional Model Experiment @ 2.5 MPa, 4:1 WAG, and ...... 10 Slugs 67
5.15. Two-Dimensional Model Experiment Carbon Dioxide Requirement ..... and Retention @ 1.0 MPa, 4:1 WAG, and 10 Slugs 69
5.16. Two-Dimensional Model Experiment Carbon Dioxide Requirement and Retention @ 1.0 MPa, 4:1 WAG, and 10 Slugs 69
5.17. Two-Dimensional Model Experiment Carbon Dioxide Requirement ..... and Retention @ 1.0 MPa, 4:1 WAG, and 10 Slugs 69
5.18. Production History of Run GTD 4 70
5.19. Production History of Run GTD 7 71
5.20. Production History of Run GTD 8 72
5.21. Production History of Run GTD 10 73
5.22. Oil Recovery Distribution of Run GTD 4 74
5.23. Oil Recovery Distribution of Run GTD 7 75
5.24. Oil Recovery Distribution of Run GTD 8 76
5.25. Oil Recovery Distribution of Run GTD 10 77
5.26. Production History of the Two-Dimensional Model Experiments @ .... 1.0 MPa, 4:1 WAG, 10 Slugs, and 2.6 m/d Brine Flow Velocity 78
5.27. Production History of the Two-Dimensional Model Experiments @ .... 1.0 MPa, 4:1 WAG, 10 Slugs, and 1.3 m/d Brine Flow Velocity 78
5.28. Phase Recoveries of the Linear Model Experiments @ 2.5 MPa, 4:1 WAG and 10 Slugs 80
5.29. Production History of Run LC 30 82
5.30. Oil Recovery Distribution of Run LC 30 83
5.31. Production History of Run LC 31 84
5.32. Oil Recovery Distribution of Run LC 31 85
5.33. Production History of Run LC 32 86
5.34. Oil Recovery Distribution of Run LC 32 87
5.35. Production History of Run LC 36 88
5.36. Oil Recovery Distribution of Run LC 36 89
5.37. Comparison of the GOR and WOR Production Histories of Run LC 31 and Run LC 32 90
5.38. Production History of the Linear Model Experiments @ 2.5 MPa, ... 4:1 WAG and 10 Slugs 92
5.39. Carbon Dioxide Requirement and Retention of the Linear Model Experiments @ 2.5 MPa, 4:1 WAG, and 10 Slugs 92

5.40. Tertiary Oil Recovery Distribution (Runs LC 34 & LC 35)................ 94
5.41. Production History of Run LC 34 and LC 35 95
5.42. Production History of Run LC 37.. 96
5.43. Oil Recovery Distribution of Run LC 37 97
5.44. Production History of Run LC 38.. 99
5.45. Oil Recovery Distribution of Run LC 38 100
5.46. Production History of Run LC 39.. 101
5.47. Oil Recovery Distribution of Run LC 39 102
5.48. Production History of Run LC 40.. 103
5.49. Oil Recovery Distribution of Run LC 40 105
5.50. Production History of Run LC 41.. 106
5.51. Oil Recovery Distribution of Run LC 41 107
5.52. Linear Model Experiments Using Live Oil @ 1.0 MPa, 4:1 WAG, ... and 10 Slugs (Phase Recoveries).. 108
5.53. Linear Model Experiments Using Live Oil @ 1.0 MPa, 4:1 WAG, ... and 10 Slugs (Line Graphs)... 108
5.54. Live Oil Run Comparison for Different Slug Sizes (Line Graph)......... 109
5.55. Live Oil Run Comparison for Different Slug Sizes (Bar Graph).......... 110
5.56. Tertiary Oil Recovery Distribution (Run LC 43 & LC 35)................. 112
5.57. Production History of Run LC 43.. 113
5.58. Comparison of Production Histories of the GOR and WOR for Live Oil and Dead Oil Sample Using Identical Parameters....................... 114
5.59. Oil Recovery Results of a Live Oil and Dead Oil Sample Using a .... 20% HCPV Carbon Dioxide Slug.. 116
5.60. Oil Recovery Distribution of Run LC 42 117
5.61. GOR and WOR Production History of the Live Oil Experiments for the Same Slug Size... 118
5.62. Live Oil Run Comparison for a 20% HCPV Carbon Dioxide Slug....... 119
5.63. Reproducibility of Live Oil Experiments Using a 20% HCPV .... Carbon Dioxide, 4:1 WAG Ratio, 10 Slugs and v=0.98 m/d............. 120
5.64. Effect of Slug Size on Total Oil Recovery.................................. 121
5.65. Effect of Slug Size on WAG Recovery... 122
5.66. Blowdown Recovery for the Two-Dimensional Model Experiments..... 124
5.67. Blowdown Recovery for the Linear Model Experiments................... 124
5.68. Blowdown Recovery for the Live Oil Experiments 124
5.69. Effect of Pressure on Carbon Dioxide Retention 125

5.70. Production History of Oil Recovery Distribution of Run GTD 2 and Run 23 (Ref.5) 127
5.71. A Comparison of the Effect of Carbon Dioxide Slug Size on Oil Recovery at 1.0 (Ref.5) and 2.5 MPa. 129
5.72. Production History of the Experiments using Same Slug Size (20%) 130
5.73. Comparison of the Production Histories for the 40% and 89% Carbon Dioxide Slug Sizes at 1.0 and 2.5 MPa. 131
5.74. Oil Recovery Distribution of Different Phases of the Experiment @ 1.0 MPa 132
5.75. Oil Recovery Distribution of Different Phases of the Experiment @ 2.5 MPa 132
5.76. Effect of the Different Phases on Oil Recovery for Linear Model Experiments @ 2.5 MPa, 4:1 WAG and 10 Slugs 134
5.77. Carbon Dioxide Requirement and Retention Values for Different Slug Sizes @ 1.0 MPa. (Ref. 6) 135
5.78. Carbon Dioxide Requirement and Retention Values for Different Slug Sizes @ 2.5 MPa 135

D1. Production History of Run GTD 2 201
D2. Production History of Run GTD 6 202
D3. Production History of Run GTD 9 203
D4. Production History of Run LC 42 204

E1. Oil Recovery Distribution of Run GTD 2 206
E2. Oil Recovery Distribution of Run GTD 6 207
E3. Oil Recovery Distribution of Run GTD 9 208

F1. Volumetric Balance on Run GTD 1 210
F2. Volumetric Balance on Run GTD 2 211
F3. Volumetric Balance on Run GTD 3 212
F4. Volumetric Balance on Run GTD 4 213
F5. Volumetric Balance on Run GTD 5 214
F6. Volumetric Balance on Run GTD 6 215
F7. Volumetric Balance on Run GTD 7 216
F8. Volumetric Balance on Run GTD 8 217

F9. Volumetric Balance on Run GTD 9 218
F10. Volumetric Balance on Run GTD 10.......... 219
F11. Volumetric Balance on Run LC 30.......... 220
F12. Volumetric Balance on Run LC 31.......... 221
F13. Volumetric Balance on Run LC 32.......... 222
F14. Volumetric Balance on Run LC 33.......... 223
F15. Volumetric Balance on Run LC 34.......... 224
F16. Volumetric Balance on Run LC 36.......... 225
F17. Volumetric Balance on Run LC 37.......... 226
F18. Volumetric Balance on Run LC 38.......... 227
F19. Volumetric Balance on Run LC 39.......... 228
F20. Volumetric Balance on Run LC 40.......... 229
F21. Volumetric Balance on Run LC 41.......... 230
F22. Volumetric Balance on Run LC 42.......... 231
F23. Volumetric Balance on Run LC 43.......... 232

NOMENCLATURE

ρ_g, ρ_o, ρ_w	Carbon Dioxide, Oil and Water Densities at Reservoir Conditions (ML^{-3})
μ_g, μ_o, μ_w	Carbon Dioxide, Oil, Water Viscosities ($ML^{-1}t^{-1}$)
σ	Interfacial Tension (Mt^{-2})
$\Delta\rho_{og}$	Oil-Carbon Dioxide Density Difference (ML^{-3})
$\vec{g}$	Vector of Gravity Acceleration (Lt^{-2})
$\Delta\rho_{wo}$	Water-Oil Density Difference (ML^{-3})
BPR	Back Pressure Regulator
Do	Molecular Diffusion of Carbon Dioxide into Oil (L^2t^{-1})
ϕ	Porosity (L^3L^{-3})
GOR	Gas-Oil Ratio
HCPV	Hydrocarbon Pore Volume (L^3)
h_M, h_P	Height of the Model and Prototype (L)
k	Absolute Permeability (L^2)
k_g, k_o, k_w	Effective Permeability to Gas, Oil and Water (L^2)
LC	Linear Core Model
Mgo	Gas-Oil Mobility Ratio (Dimensionless)
Mwo	Water-Oil Mobility Ratio (Dimensionless)
OOIP	Original Oil-In-Place (L^3)
OPFIR	Oil Produced Fluid Injected Ratio
Q	Injection Flow Rate (L^3t^{-1})
ρ	Density (ML^{-3})
Req	CO_2-Requirement (L^3L^{-3})
Ret	CO_2-Retention (% Inj)
RHCPV	Residual Hydrocarbon Pore Volume (L^3)
Sg, So, Sw	Gas, Oil, and Water Saturations (L^3L^{-3})
Soi	Initial Oil Saturation (L^3L^{-3})
Swc	Connate Water Saturation (L^3L^{-3})
TD	Two-Dimensional Model
V	Superficial Velocity (Lt^{-1})
Vg*, Vw*	Slug Volumes of Carbon Dioxide and Water (Fraction of the HCPV of the System) ($L^3 L^{-3}$)
WAG	Water-Alternating-Gas (Ratio)
WOR	Water-Oil Ratio

1. INTRODUCTION

The immiscible carbon dioxide flooding process holds promise for moderately viscous heavy oils, occurring in thin formations, which are often unsuitable for thermal methods, such as steam injection and *in situ* combustion. This is especially true for some of the heavy oil reservoirs in Alberta, Saskatchewan, and other regions, where the formations are thin (<5 m), the reservoir depths are large (>500 m), oil saturation is often low and other geological conditions, such as contiguous water zones are present. Approximately 85% of Saskatchewan's heavy oil formations are less than 5 m thick. Carbon dioxide flooding may provide an alternative to thermal methods for these thin heavy oil reservoirs.[1] A current immiscible carbon dioxide field test in the Retlaw Upper Mannville V pool in southern Alberta has already a cumulative oil production which exceeds 119,240 m^3 from the project's 25 producing wells since January 1991.[2]

The flooding process consists of injecting small volumes of carbon dioxide, alternating with slugs of water. After the total volume of carbon dioxide is injected, water injection is continued until an arbitrary water-oil ratio of 20 sm^3/sm^3 is achieved. At this point, the blowdown phase is started by lowering the pressure to atmospheric pressure.

Studies conducted by Klins and Farouq Ali[3], Rojas[4], and Rojas and Farouq Ali[5] employing numerical simulation and scaled models, respectively, showed that this process can recover 10 to 30% incremental oil compared to a waterflood. The numerical model was used to study the process alternatives.

Previous work[4,6,7] showed that the efficiency of the immiscible carbon dioxide flooding process depends on several variables including the total volume of carbon dioxide and water injected, the WAG ratio, the number of slugs used, the operating pressure, the respective injection rates of carbon dioxide and water slugs, oil saturation, gas saturation, oil viscosity, factors relating to rock and fluid properties, and the extent of phase equilibrium.

2. STATEMENT OF THE PROBLEM

The objectives of the present research were to investigate and advance the technology of the immiscible carbon dioxide flooding of heavy oil, and its applicability to thin, heavy oil reservoirs. The specific objectives of the present research were as follows :

1. Modification of the existing apparatus :

1.1 To calibrate the gas injection system and to improve the accuracy of the gas flow controller by installing a gas booster. This would make it possible to inject a predetermined volume of gas at any pressure.

1.2 To design an accurate gas metering system at the downstream end to measure the volume of the gas produced.

1.3 To prepare live oil mixtures for carbon dioxide floods.

2. To conduct experiments in the two-dimensional model with the following specific objectives :

   2.1 To analyze the results when experiments are conducted using the parameters of the previous experiments in the linear model, especially with regard to different production mechanisms.
   2.2 To examine the effect of operating pressure.
   2.3 To study the effect of flow rate.

3. Comparison of the one-dimensional and two-dimensional model experiments.

4. To conduct experiments in the one-dimensional model with the following objectives :

   4.1 To compare experiments conducted at 2.5 MPa with those conducted previously at 1 MPa.
   4.2 To study the effect of carbon dioxide slug size on oil recovery particularly when very small slugs are utilized.
   4.3 To compare the present results with the previous ones, and to do additional analyses of the two sets.

5. To conduct experiments using oil with gas in solution, and to assess the effect of solution gas on the performance parameters.

3. REVIEW OF THE LITERATURE

Primary and secondary recovery of conventional oils averages 33%. In the case of heavy oils (10 to 20 °API), this performance is 2 to 5%. For the Lloydminster heavy oil reservoir, the total recovery is often 2% of the initial oil-in-place. Additional oil recovery would require the application of costly, and often unproven, EOR methods such as steamfloods and *in situ* combustion.

There are two classes of carbon dioxide flooding processes: the miscible process, which is best suited for light and medium gravity crude oils, and the immiscible process, which is more applicable to heavy oils, although it has been applied to light oils as well.[8,9,10]

The immiscible carbon dioxide flooding process is a non-thermal recovery method, which has considerable promise for a range of heavy oil reservoirs. In this method, a slug of carbon dioxide gas is injected into the formation, which mobilizes the oil contacted and displaces it towards the production well. Oil mobility is improved due to the solubility of carbon dioxide in the oil which causes a reduction in the viscosity, and an increase in the volume.

3.1 The Miscible Carbon Dioxide Flooding Process

In miscible carbon dioxide flooding operations, liquid (more correctly, above the critical point) carbon dioxide is injected into the reservoir to form a single phase solution with the in-place oil which is thus displaced as a highly mobile phase. Moreover, the retentive force of capillarity, which is a significant factor in reducing the recovery efficiency in conventional flood operations, is eliminated or minimized due to a reduction in interfacial tension. This method provides an effective displacement of the oil in the areas swept by the liquified carbon dioxide, so that a low residual oil saturation is obtained. The efficiency of the process depends on reservoir temperature and pressure, which influence the crude oil-carbon dioxide miscibility. For economic reasons, a slug of carbon dioxide followed by water (or other displacing agent) is employed usually instead of a continuous flood.[11]

Unlike light hydrocarbons, carbon dioxide is not a first-contact miscible solvent with respect to a crude oil. Carbon dioxide, upon several contacts with the crude oil, extracts light hydrocarbons, thereby developing a hydrocarbon-containing solution at the interface between carbon dioxide and crude oil. This solution can dissolve other heavier hydrocarbons. These hydrocarbons enter the solution to form a single phase which is carried through the reservoir, gradually dissolving heavier hydrocarbons as the flood advances.

The minimum pressure required to develop miscibility with the reservoir crude oil at reservoir temperature is called the Minimum Miscibility Pressure or MMP. This pressure varies according to the nature of the oil as well as other factors. Some oils may not be able to attain the minimum miscibility pressure due to the impracticability of pressurizing the reservoir. When the minimum miscibility pressure cannot be achieved in the reservoir, the process is immiscible in character. The C_5 to C_{30} content of heavy oils is too low to sustain a miscible carbon dioxide displacement, and therefore the carbon dioxide process for the recovery of heavy crude would be immiscible in nature.[12] The carbon dioxide requirement in such a process is often less than 100 m^3/m^3, which is far below the gas requirements per m^3 of oil for the miscible carbon dioxide process,[1,4,13-14] or the air requirement in *in situ* combustion. Carbon dioxide requirement is a parameter used in assessing the economics of the process and is defined as the ratio of the total carbon dioxide injected (sm^3) to the total volume of oil produced (sm^3).

3.2 The Immiscible Carbon Dioxide Flooding Process

There are several variations of the immiscible carbon dioxide process that have been proposed for recovering heavy oil. As the carbon dioxide alone cannot displace the oil efficiently, the recovery process must be supplemented by a suitable mobility control method.[4,5,7,15] The variations of the basic process are discussed below.

3.2.1 Continuous Injection of Carbon Dioxide

In this process, carbon dioxide gas is injected continuously until the oil production is very low and a high gas-oil ratio is reached. This process is not likely to be practical (economically) even if the gas is recycled. Basically, in all gas injection processes, the lack of mobility and gravity control lead to a low sweep of a significant portion of the reservoir. Scaled model studies by Rojas[4] showed that the carbon dioxide requirement for this process was up to ten times that of the WAG process, discussed below, and that this process under subcritical conditions was not applicable to heavy oils of the Aberfeldy-Lloydminster type. In this case, the immiscible displacement of these viscous oils by carbon dioxide was completely dominated by viscous forces, and the mass transfer between carbon dioxide and crude oil did not appear to enhance the recovery appreciably.

3.2.2 Carbonated Waterflooding

In this process, a mixture of carbon dioxide and water, or carbonated water is injected into the reservoir. Carbon dioxide tends to diffuse out of the injected water-carbon dioxide mixture when it contacts the reservoir oil. Such diffusion is relatively slow when compared to that in the injection of a pure carbon dioxide gas slug. A schematic diagram of the process is shown in Fig. 3.1.

3.2.3 Simultaneous Water-Carbon Dioxide Injection Process

In this process, water and carbon dioxide are injected simultaneously through a dual injection system. Water is injected at the top of the pay zone and allowed to segregate downwards as it flows through the reservoir while carbon dioxide gas is injected at the bottom and allowed to rise. The resulting improved recovery is, however, offset by the high operating and completion costs. Figure 3.2 is a schematic diagram of this process.

3.2.4 Carbon Dioxide Slug Process

In this process, a precalculated volume of carbon dioxide gas is injected into the reservoir. This is followed by continuous water injection to drive the carbon dioxide slug through the reservoir. Carbon dioxide gas is immiscibly displaced by the water, leaving a residual carbon dioxide saturation in the reservoir. Figure 3.3 is a schematic of this process.

3.2.5 Immiscible Carbon Dioxide WAG Process

The immiscible carbon dioxide WAG (Water-Alternating-Gas) process consists of alternating injection of small volumes (5% or less) of carbon dioxide and water until the desired volume of carbon dioxide gas (usually 20 to 30% PV at the operating pressure) has been injected. This process is followed by continuous injection of water until the producing water-oil ratio reaches some economic cut-off value, e.g. 20:1. Water injection serves to drive the mobilized oil (lowered viscosity, increased volume) towards the production well, thus resulting in a waterflood at an improved mobility ratio. Once the economic limit is reached, water injection is discontinued and the reservoir is

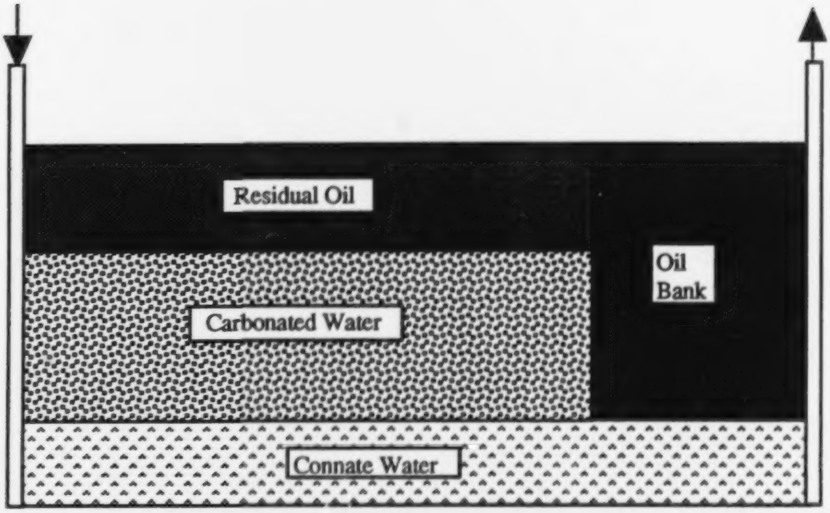


Figure 3.1 Schematic of Carbonated Waterflooding Process.

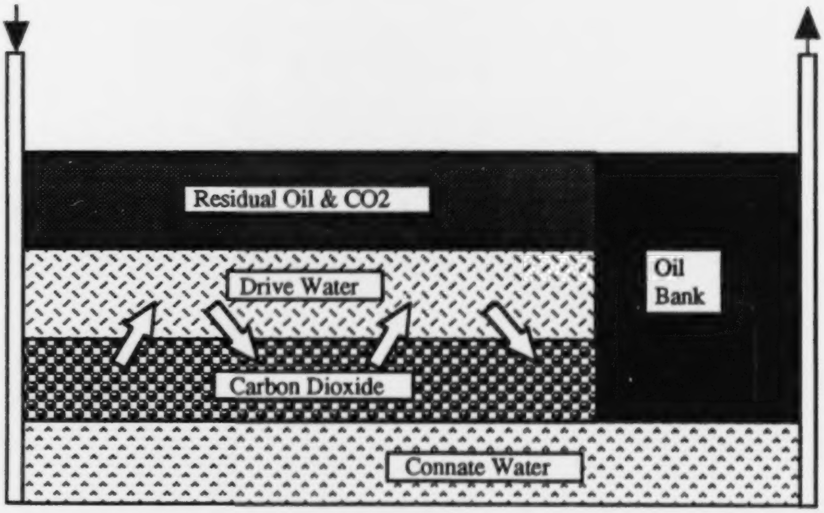


Figure 3.2: Schematic of Simultaneous Water-CO2 Injection Process.

(After Ref.15)

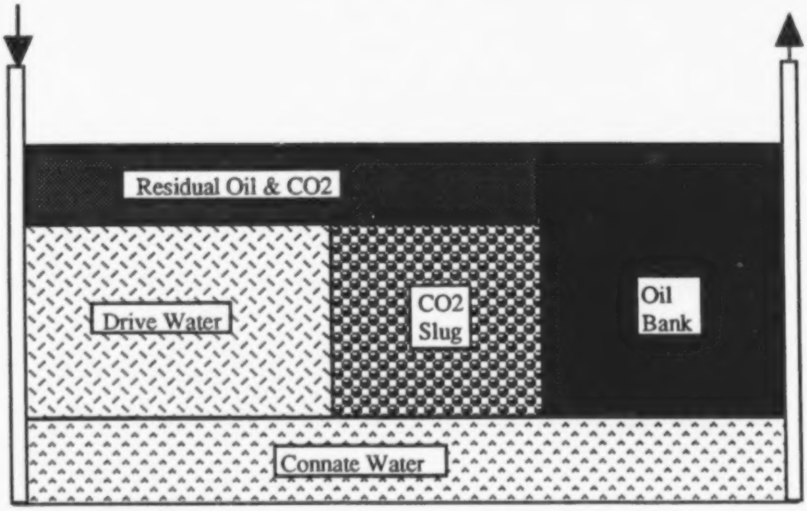


Figure 3.3: Schematic of CO2 Slug and Water Drive Process.

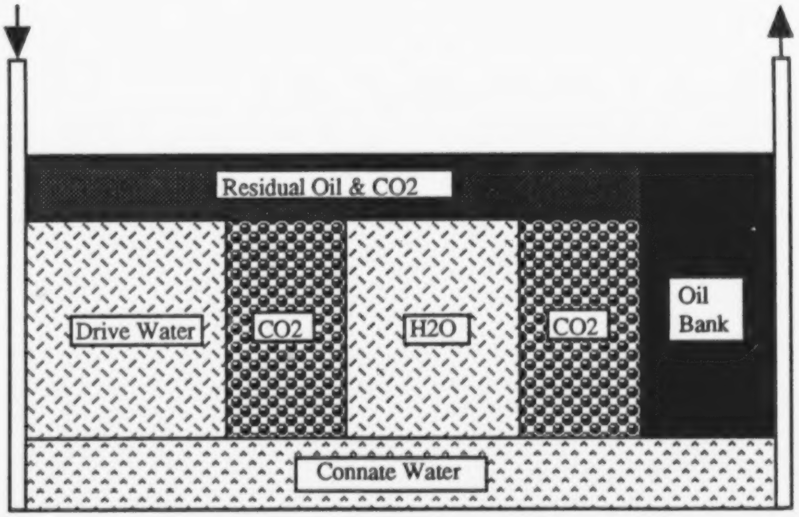


Figure 3.4: Schematic of Water Alternating Gas (WAG) CO2 Process.

(After Ref.15)

allowed to blowdown (production end pressure is lowered), which results in additional recovery.

The water-alternating-gas ratio is defined as the ratio of the volume of water to that of carbon dioxide at reservoir conditions. This process provides mobility control and promotes better mixing of carbon dioxide and water. A schematic of this process is illustrated in Fig. 3.4.

One important objective of alternating carbon dioxide and water is to reduce the carbon dioxide mobility. Klins[15] mentioned that the process also promotes uniform entry into the reservoir, thus yielding a high volumetric sweep efficiency. The WAG process reduces the mobility of carbon dioxide because water blocks the carbon dioxide invaded zones and slows down the advance of carbon dioxide, thereby preventing its rapid production.[16]

In addition to the increased oil recovery, the immiscible WAG process has several indirect benefits. Champion and Sheldon[17] stated that, due to the alternating injection of gas and water, a smaller volume of gas broke through to producing wells, thus reducing the gas handling requirements. Also, the lower producing gas-oil ratio's associated with WAG injection result in reduced erosion of the producing equipment. For the Kuparuk River Field's project, oil production rate is controlled by the field gas handling capacity. Reducing the amount of gas handling by using WAG injection enables the field oil production rate to be increased.[17]

3.2.6 Carbon Dioxide Huff n' Puff Process

Haskins and Alston[18], Simpson[19], and Monger and Coma[10] described the carbon dioxide huff n' puff process as a method of single well carbon dioxide stimulation. This recovery method is ideally suited for small operators who may not be able to make the large capital investments necessary for fieldwide floods. Cyclic injection may also be the only possible EOR option for smaller discontinuous reservoirs as this single well process does not require well-to-well displacement.[8] A schematic of this process is shown in Fig. 3.5.

The general procedure is to inject a large volume of carbon dioxide at high pressure down a producing well and shut in the well for a period of time to soak (i.e. allow carbon dioxide to dissolve in the oil). Following the soak period, the pressure is reduced and the released gas drives the mobilized oil to the well.[20] The efficiency of the process is measured by the volume of incremental oil recovered per unit of carbon dioxide injected.[21] The carbon

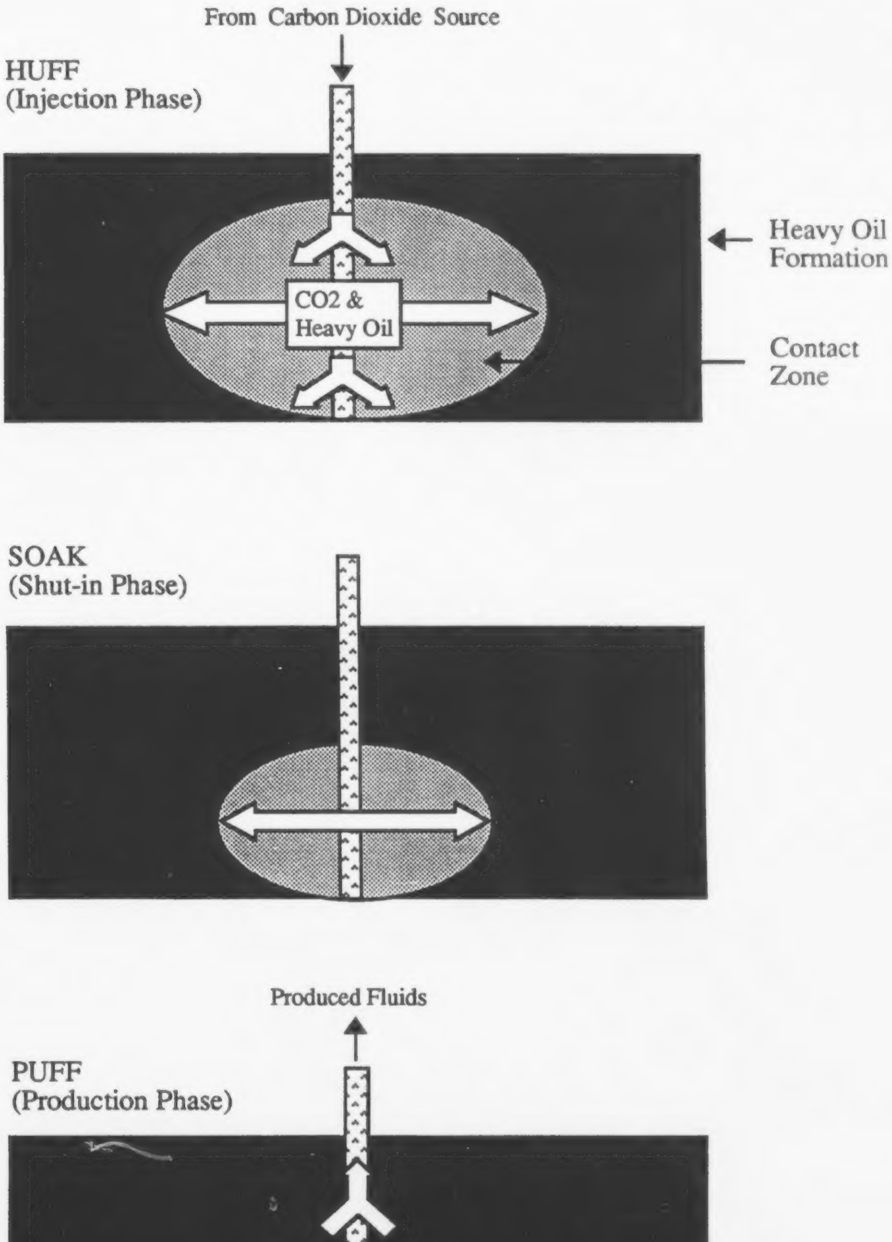


Figure 3.5 : Cyclic Huff n 'Puff Stimulation Process.

dioxide huff n' puff process, if successful, provides quick payout with a low capital investment.

Thomas and Monger-McClure[9] obtained results for 106 light-oil, single-well carbon dioxide huff n' puff field tests. They suggested that one month was an optimal soak period for most cases. The authors observed that the carbon dioxide field tests were able to recover incremental oil in proportion to the mass of carbon dioxide injected. The economic criterion adopted was a carbon dioxide utilization $< 540\ sm^3/\ sm^3$, and of the 97 field tests that produced incremental oil, 87 met the criteria, with an average carbon dioxide utilization of 234 sm^3/sm^3. Optimum carbon dioxide slug size depended on field conditions, where the economic size for any given field application depends on the balance between site-specific carbon dioxide, workover costs and field-tested carbon dioxide utilization.

In reservoirs with low interwell communication, the single well approach may afford the only means of recovering oil by a carbon dioxide process. In reservoirs where interwell communication is not a problem, carbon dioxide huff n' puff offers a fast, inexpensive alternative to traditional methods.[22] The presence of nitrogen or methane as contaminants in carbon dioxide is detrimental because oil recovery is reduced.

While the carbon dioxide huff n' puff is similar to cyclic steam stimulation in the heavy oil formations, cyclic carbon dioxide projects are not limited to heavy oil since the technique has been used successfully to recover light oils with relatively low utilization of carbon dioxide. The wells should be at or near the economic limit prior to the initiation of carbon dioxide injection.

The productive life of a carbon dioxide huff n' puff operation is limited to two or three cycles as the oil recovery in following cycles is drastically reduced.[18] When considering light oil projects, it was found that oil recovery increases with the amount of carbon dioxide injected, and that the rate response to repeated cycles, despite being still favourable, shows a decline.[10]

3.3 Carbon Dioxide Properties Which Play a Role in Immiscible Processes

Presented below is a brief discussion of the characteristics of carbon dioxide and its transport properties, its relation to heavy oil and reservoir water, its influence on the rock matrix characteristics which affect oil recovery, and the use of other gases in the reservoir.

Also a brief description of field tests with respect to the huff n' puff process and the WAG process is given.

3.3.1 Heavy Oil Properties

Crude oils are often classified according to their API gravity. Heavy oils have API gravities ranging from 10 to 20° API (density from 1000 to 943 kg/m^3 at 15.6°C), and viscosities from 100 to 10,000 mPa.s at reservoir temperature.[23] Most heavy oils contain very little solution gas.

A distillation analysis conducted by Chung *et al.*[20] showed that heavy crude oils contain more than 40% residuum, a non-volatile fraction made up of a complex mixture of asphaltenes, resins, polymers and other compounds. The asphaltene content of heavy oils is usually above 10 percent by weight. All these compounds contribute to the high viscosity of the heavy oils. Thus, oil viscosity varies with the content of heavy ends. Information on the composition of the residuum is required to predict heavy crude oil viscosity.

3.3.2 Properties of Carbon Dioxide

Carbon dioxide is a relatively dense gas with a density greater than that of air at atmospheric conditions, and a low compressibility factor at normal reservoir conditions. Rojas[4] noted that the viscosity of some heavy oils could be reduced by a factor of 10 due to the solution of carbon dioxide in oil. Also, the oil volume expands on the order of 10%. The carbonic acid formed by the solution of carbon dioxide in water reacts with the oil and forms narrow emulsion banks which help to stabilize the displacement front. As a result, the oil cut increases, or the oil is mobilized, if initially at residual saturation. The swelling and viscosity reduction phenomena render the effective mobility ratio more favourable. Swelling will lead to an increase in the oil saturation, resulting in improved oil recovery.

The solubility of carbon dioxide in oil increases with an increase in pressure. Solubility depends on the saturation pressure, reservoir temperature, composition of the crude oil, and only partially on the specific gravity of the oil. The solubility of carbon dioxide in oil decreases as oil API gravity decreases. These factors also determine the increase in the volume of oil as a result of solution.[24]

Carbon dioxide can also be used for the solution gas drive recovery of relatively viscous medium and light oils. Carbonation reduces oil viscosity and increases the oil volume. The solubility of carbon dioxide in oil increases with an increase in pressure and a decrease in temperature.

3.3.3 Transport Properties of Carbon Dioxide in Heavy Oil

The three main transport processes by which carbon dioxide mixes with the reservoir fluids are solution, diffusion and dispersion.

3.3.3.1 Solution

Solubility of carbon dioxide in heavy oil is the most important transport process with regard to oil recovery. The solubility of one substance in another depends fundamentally upon the ease with which the two molecular species are able to mix.[25] Thus, solubility is proportional to the attractive forces between the molecules of substances under consideration. It has been shown that the solubility of carbon dioxide in crude oil is higher than that of air and natural gas.[4]

Simon and Graue[26] conducted one of the earliest studies of carbon dioxide solubility in oil, employing nine oils with gravities ranging from 11.9 to 33.3° API. The experimental conditions covered a range of temperatures from 38 to 121°C and pressures up to 15.9 MPa. They developed a set of generalized correlations for predicting solubility, swelling and viscosity behaviour of carbon dioxide-crude oil systems from their experimental data. The correlations were presented in graphical form using mole fraction instead of volume fraction for compositional units. Thus, the molecular weight of heavy crude will have to be known to use the correlations.

Rojas[4] showed that carbon dioxide, when dissolved in heavy oil and bitumen, could increase their volume (10 to 20%), and reduce their viscosity (>90%). Miller and Jones[27] found that at supercritical temperature, the solubility of carbon dioxide gas and the volumetric expansion of heavy oils increase with increasing pressure and decreasing temperature. They also showed that the solubility of carbon dioxide gas in conventional heavy oil at moderate pressures (4 to 6 MPa) and temperatures (20 to 25°C) is of the order of 50 to 100 sm^3 in a standard cubic metre of oil, yielding an increase in volume between 10 and 20%. It was found that the solubility of gaseous carbon dioxide in oil was a strong function of pressure, while the solubility of liquid carbon dioxide was not as sensitive to pressure. Displacement experiments conducted by Beeson and Ortloff[28] using carbon dioxide demonstrated that higher recoveries were obtained when an equal mass of carbon dioxide, driven by water, was injected as a gas rather than as a liquid.

The solubility of a gas in liquids normally decreases with an increase in temperature at low pressures because light components (gas molecules) tend to vapourize at high temperatures.[20] As pressure increases, however, liquid becomes more dense at lower temperatures, i.e. molecules in the liquid phase are packed more tightly together and thus leave less room for gas molecules to enter.

The solubility of carbon dioxide in water is an important factor in a stimulation process and is much lower than that in crude oils.[15,25,29] The solubility of carbon dioxide in water depends on pressure, temperature and salinity of the water. This is an important factor to consider when carbon dioxide is injected with water (WAG). Dodds, Stutzman, and Sollami[30] presented a study of carbon dioxide dissolved in distilled water, and they concluded that an increase in the salinity of the reservoir water decreased the gas solubility significantly.

3.3.3.2 Diffusion

Diffusion is defined as a process where matter is transported from one part of a system to another due to random molecular motion, and is independent of any convective forces in the system.[25] Diffusion helps carbon dioxide to penetrate heavy oils, and serves to reduce viscous instabilities.[26]

In most instances, the dissolution of carbon dioxide in oil is through the process of diffusion. Molecular diffusion of carbon dioxide is considered to be a slow process, especially when the water phase surrounds the oil phase.

McManamey and Woollen[31] presented the following equation to calculate the diffusion coefficient (D_o) of carbon dioxide in organic liquids at atmospheric conditions.

$$D_o = 1.41 \times 10^{-10} \mu_o^{-0.47}$$

where D_o is in cm^2/s and μ_o is in mPa.s.

Denoyelle and Bardon[32] found that the diffusion coefficient of carbon dioxide increased with an increase in pressure, and the calculated values were higher than the values reported for atmospheric conditions. They calculated the diffusion rate of carbon dioxide in a liquid containing both oil and water and found that it was between the values for water alone and oil alone.

Schmidt, Leshchyshyn, and Puttagunta[33] calculated carbon dioxide diffusivity in the Athabasca bitumen and found that the results were of the same order as those observed for most liquid systems, and that carbon dioxide diffusivity was a function of concentration.

Rojas and Farouq Ali[25] showed that the diffusivity of carbon dioxide at elevated pressures for heavy oils was much higher than the values calculated using the formula of McManamey and Woollen.[31] They concluded that, while the diffusivity of carbon dioxide in heavy oils was high, it was still not high enough to mobilize appreciable amounts of oil from uninvaded zones.

3.3.3.3 Dispersion

When fluids are flowing through a porous medium, mixing may be greater than that due to diffusion alone, signifying that dispersion is made up of diffusion and mechanical mixing due to fluid velocity.[34] The low dispersion of carbon dioxide in heavy oils is insufficient to damp out the carbon dioxide "fingers" in the immiscible displacement of oil by subcritical carbon dioxide.

3.3.4 Influence of Carbon Dioxide on Oil, Water and Formation Properties

3.3.4.1 Viscosity Reduction

The large reduction in the viscosity of heavy oils, when saturated with carbon dioxide, is the most important phenomenon in the immiscible carbon dioxide flooding process. The viscosity of carbon dioxide at reservoir conditions depends mainly on the prevailing temperature and pressure. Due to the relatively low solubility of carbon dioxide, the viscosity of formation water is often assumed to be independent of carbon dioxide saturation. The viscosity of an oil sample saturated with carbon dioxide depends on the temperature, pressure, and concentration of the dissolved carbon dioxide.

Chung, Jones, and Burchfield[20] reported that the viscosity of heavy oils increased with pressure, but dropped significantly with carbon dioxide saturation. They reported that saturating a crude oil with carbon dioxide at 60°C and pressures above 6.9 MPa will reduce its viscosity more than heating it from 60 to 94°C.

The experimental results of Jacob *et al.*[35] illustrated the effect of dissolved carbon dioxide, methane, and nitrogen on the viscosity of Athabasca bitumen. They showed that carbon dioxide reduced the bitumen viscosity more than the other gases, especially at temperatures below 100°C.

Chung *et al.*[20] reported that in an immiscible carbon dioxide process, a reduction of one order of magnitude of original oil viscosity could be achieved if the oil was saturated with carbon dioxide at pressures above 6.9 MPa. The viscosity of carbon dioxide saturated heavy oils begin to increase at high pressures because the density of carbon dioxide/heavy oil mixture increases at high pressures. In general, the viscosity of carbon dioxide/heavy oil mixtures is a function of the composition. This composition dependent function is extremely complex for the carbon dioxide/heavy oil mixtures. Because it is nearly impossible to obtain the detailed composition of heavy oil and the contribution of each component to the mixture viscosity, the carbon dioxide/heavy oil mixture was treated as a binary system with two components: pure carbon dioxide and heavy oil.

Another important factor that affects the viscosity of heavy oil-carbon dioxide mixtures is the time required to achieve equilibrium between the two fluids. At equilibrium, the viscosity of the mixture does not change with time. According to Rojas[4], at times less than the equilibrium time, the viscosity of the two phase mixture decreased with time.

Studies conducted by Rojas and Farouq Ali[25], Miller and Jones[27], Shu[11], and other researchers[15,36] showed that the higher the initial oil viscosity, the greater the percentage reduction of oil viscosity when saturated with subcritical carbon dioxide. This is also true in the case of the viscosity-temperature relationship. Thus, viscosity reduction is greater with medium and heavy oils than with light oils. At temperatures above 150°C, the effect of carbon dioxide on oil viscosity is minimal. Dyer[7] reported large reductions in oil viscosity at carbon dioxide saturation pressures. Sayegh and Maini[37] reported that the viscosity of heavy oil increased appreciably with increasing pressure.

A study by Jha[38] showed that a forty-five fold reduction in viscosity and a 16% increase in the swelling factor were observed in a Lloydminster type heavy oil-carbon dioxide system at 28°C and with pressures up to 8.27 MPa.

Flock and Boogmans[39] reported that carbonation had only a slight effect on the viscosity of water. Due to the relatively low solubility, the viscosity of water was assumed to be independent of the carbon dioxide saturation. Tumasyan, Panteleev and Meinster[40] studied the effect of carbonation on water and showed that carbon dioxide solution in filtered tap water, at high pressures, slightly increased the water viscosity.

3.3.4.2 Swelling

According to the work conducted by Simon and Graue[26], and Rojas[4], swelling or expansion factor is an important effect in oil recovery because the volume of residual oil left in the reservoir after waterflooding is inversely proportional to the swelling factor; i.e. the greater the swelling, the less is the stock tank oil left in the reservoir. Chung *et al.*[20] defined the swelling factor as the ratio of the volume of the carbon dioxide saturated oil at the temperature and pressure of the system and the volume of the dead oil (no solution gas) at the system temperature and standard pressure (101.325 kPa).

An important fact about swelling is that the increase in volume will lead to an increase in oil saturation, thus allowing the discontinuous oil droplets previously trapped in the pores to merge with the flowing oil phase, and eventually lower the oil saturation left in the porous medium.

An increase in carbon dioxide solubility increases the swelling. Swelling factors increase sharply at pressures below the carbon dioxide bubble point pressure. The magnitude of swelling for heavy oil is less than 20% at pressures below 20.7 MPa. Oil swelling appears to play a major role in forming an oil bank[41], and as a result fewer stock tank volumes of residual oil are left in place.

3.3.4.3 Effects of Interfacial Tension

Rojas and Farouq Ali[25] found that although a reduction of interfacial tension from 25 (at 1 MPa) to 16 mN/m (at 5.5 MPa) did not increase the capillary number much, it did lead to the *in situ* formation of brine-in-oil emulsions, which enhanced oil recovery by carbon dioxide/brine injection. They also reported that the interfacial tension between Aberfeldy heavy oil and carbonated brine decreased moderately with increasing carbonation pressure of brine. They attributed the reduction in interfacial tension to the action of carbonic acid on the nitrogen bases found in the Aberfeldy heavy oil.

Rojas[4] mentioned that viscous gasified emulsions were observed after brine breakthrough in the displacement tests. The emulsions had a viscosity higher than that of the oleic phase. These emulsions were believed to form *in situ* rather than in the production facilities of the model.

3.3.4.4 Effects of Velocity and Temperature

Rojas and Farouq Ali[25] noted that oil recovery at carbon dioxide breakthrough decreased slightly with increasing injection rate, while the oil recovery at brine breakthrough increased moderately. They speculated that the low superficial velocity of carbon dioxide enabled the beneficial effect of diffusion while the high superficial velocity of brine improved the recovery by increasing the emulsification mechanism and by decreasing the ratio of gravitational to viscous forces.

Low reservoir temperatures will promote carbon dioxide solubility in oil, but will also increase oil viscosity and decrease carbon dioxide-oil mass transfer. Thus, low temperatures could cause a marked reduction in oil recovery and an increase in the carbon dioxide requirements.[22]

3.3.4.5 Asphaltene Flocculation

In field tests of the carbon dioxide pilot in the Midale Unit, directly after carbon dioxide breakthrough in the production wells, a substantial amount of solids consisting of wax, trapped oil and asphaltenes was found in the wellbore equipment. Such deposition can generate serious problems such as constriction of fluid flow passages or injectivity problems related to wettability reversal. These problems seldom occur in primary and secondary operations. Similar deposition of solids has been reported by operators of gas injection projects.[42] Novosad and Costain[42] described asphaltenes as molecular elements dissolved in oil, as colloidal particles, or as a combination of both. Although asphaltenes are described in various ways, it is apparent that their physical structure in crude oil and the mechanism of their precipitation remain to be determined exactly.

Strausz[43] stated that asphaltene precipitation occurred when the hydrocarbons and the polar oil fractions lost their ability to disperse colloidally the asphaltene fraction. Some acids when in contact with crude oil may precipitate asphaltenes, thus plugging the pores.

The fluid composition, system pressure and temperature determine asphaltene behaviour.[42] Klins[15] and Holm[44] noted that an important factor in considering the recovery process in the formation of interest was the initial proportion of asphaltene base ends in crude oil.

3.3.4.6 Mobility Control Agents

Currently, foams are being tested to reduce the mobility of carbon dioxide in immiscible floods.[16] Foaming agents are evaluated for their ability to produce ample, lasting foam and to have low loss from adsorption on reservoir rock and decomposition at reservoir conditions.[45] Direct thickeners, like polymers, added to carbon dioxide are also being tested as mobility control agents. It is possible that such mobility control agents could be adapted to the immiscible carbon dioxide floods also.

Islam[46] carried out physical model experiments using different mobility control agents to recover oil from bottom water reservoirs. He found that foam generated *in situ* performed the best when the bottom water permeability was the same as the oil zone permeability. In addition, it was found that a 10% O/W emulsion (200 ppm surfactant in the water phase) was most effective in blocking the bottom-water zone and that the minimal volume of emulsion slug required to produce any blockage was one pore volume of the bottom-water zone. Murji[47] studied the problem of bitumen mobilization under reservoir, i.e. cold conditions. It was found that solvents and solvent/surfactant combinations were successful in mobilizing bitumen, under reservoir conditions, from reservoirs that had bottom water.

In many fluid displacement processes, viscous fingering occurs when the displacement is conducted at an unfavourable mobility ratio. The adverse mobility displacements are often characterized by early breakthrough of the injected fluid (gas) and low sweep efficiency. The viscous fingers tend to develop high mobility paths leading from the injection to the production well. The released gases drive the oil to the production well. This is the principle of the carbon dioxide huff n' puff stimulation process.

3.3.4.7 Blowdown Recovery Mechanism

The blowdown mechanism is similar to that of solution gas drive during the normal depletion of an oilfield. However, at the same conditions of pressure, temperature, saturation and crude oil composition, the blowdown recovery in carbon dioxide floods is higher than that in normal gas floods due to the higher expansion and solubility of carbon dioxide in oil.[4]

Blowdown recovery can be defined as the oil recovered upon termination of a flood by depleting the reservoir pressure to the abandonment pressure. The main drive mechanism is the expansion of oil, water, and free and dissolved carbon dioxide in the reservoir.[5]

Beeson and Ortloff[28] noted that up to 30% of the initial oil-in-place may be recovered by means of the solution gas drive mechanism. Wang[41] observed that as the system pressure was lowered, gas bubbles evolved vigorously from the residual oil and consequently, large amounts of trapped oil were mobilized and recovered during the blowdown phase.

It should be noted that the gas phase is not generated until the pressure in the system is reduced. Part of the gas formed would occupy pore spaces previously occupied by the produced fluids. When reducing the pressure, expansion of the carbon dioxide provides drive energy so that all three phases present (gas, water and oil) would become mobile.

3.3.5 Other Gases (Nitrogen and Methane)

Nitrogen and methane usually occur in the reservoir and are considered to be contaminants when mixed with carbon dioxide, as these gases affect the displacement process. Methane is used as the gas for many solution gas drive methods, while nitrogen has been used as an alternative to carbon dioxide for operating at very high pressures, especially when carbon dioxide is not available.

3.3.5.1 Effect of Nitrogen on Oil Recovery

Results of a one-dimensional simulation by Spivak and Chima[48] showed that the volume of nitrogen dissolved in the oil was small. They explained that as nitrogen is essentially insoluble in oil, it contributed to an increased free gas saturation. Chung and Burchfield[22] stated that the incremental oil recovery after breakthrough was small for a nitrogen coreflood experiment when compared to a carbon dioxide experiment using the same parameters. They also concluded that the effect of nitrogen depended on the fluid saturation inside a core: if there was a free gas saturation in the core, the effect of nitrogen may not be significant.

Experiments conducted by Zhu,[6] using nitrogen instead of carbon dioxide, indicated that the oil recovery was essentially equal to the waterflood recovery plus the blowdown recovery due to gas expansion. Therefore, it was concluded that the use of a non-condensable gas such as nitrogen in place of carbon dioxide did not lead to incremental oil recovery.

The study conducted by Novosad and Costain[42] showed that for a highly viscous oil (> 5000 mPa.s), carbon dioxide recovered more oil than nitrogen. They also observed that oil presaturated with nitrogen eliminated the effects of gas diffusion and dispersion.

Sayegh and Maini[37] conducted laboratory experiments of the carbon dioxide huff n' huff process to evaluate its suitability to heavy oil reservoirs in Alberta. They used nitrogen to pre-saturate the oil used for the experiments as nitrogen eliminated the effects of gas diffusion and dispersion. Nitrogen was used instead of carbon dioxide to assure that the influence of dissolved gas would be small.

3.3.5.2 Effect of Methane on Oil Recovery

In general, methane reduces the efficiency of the immiscible carbon dioxide flooding process due mainly to its lower solubility.[37] It should be noted, however, that during primary depletion, the dissolved gas is not carbon dioxide but mostly hydrocarbon gas. Jacobs *et al.*[35] stated that methane had only a small effect on reducing the bitumen viscosity.

3.4 Laboratory Studies

A number of studies[4,6-7] on the immiscible carbon dioxide WAG flooding process were carried out previously at the University of Alberta. These are described in the following paragraphs.

Rojas[3] derived the scaling groups for the immiscible carbon dioxide WAG flooding process, and used these scaling groups in the design and construction of a two-dimensional physical model. A series of experiments using carbon dioxide and water were carried out in the two-dimensional model at an average operating pressure of 5.5 MPa, and room temperature (21 to 23°C). This was followed by the work of Zhu[6] who conducted experiments in the two-dimensional model, using both carbon dioxide and nitrogen at two different operating pressures: 5.5 and 2.5 MPa. Dyer[7] performed a series of experiments in a linear model using carbon dioxide at low pressures (1.0 and 2.5 MPa). Table 3.1 provides a summary of the rock and fluid properties of the prototype.

TABLE 3.1

ROCK AND FLUID PROPERTIES OF THE PROTOTYPE

(Data taken from Rojas[4])

Aberfeldy Lloydminster reservoir
Horizontal, unconsolidated marine sand

Net Sand Thickness	6.1 m
Pattern Size (5-spot)	6.4 ha
Porosity	35 %
Permeability	1 to 3 darcies
Oil Saturation	87 %
Gas Saturation	0 %
Depth	500 to 600 m
Reservoir Temperature	21 to 22°C
Oil Gravity	15 to 17° API
Oil Viscosity	1000 to 5000 mPa.s
Original Solution GOR	9 sm^3/sm^3

3.4.1 Physical Model Scaling Methods

In general, two types of scaled physical models are used to study fluid flow in porous media: partially scaled and fully scaled. In partially scaled models, some aspects of the flow process being studied are scaled while the other aspects are not. Consequently, some information concerning the flow process is required. These models can be used to predict certain parameters of the flow process, specifically with regard to those aspects that are scaled. Fully scaled models are very complex and difficult to build and operate. For these models, every aspect of the flow process under investigation is scaled. In reality, it is impossible to satisfy all of the scaling requirements. This is especially true for physical models used to study fluid flow in porous media. These two types of scaled physical models require the derivation and application of different scaling groups for the flow process in their design and construction. There are two methods for deriving these scaling groups: dimensional analysis and inspectional analysis.

3.4.1.1 Dimensional Analysis

Langhaar[49] classified dimensional analysis as a method by which information on a phenomenon can be deduced from a single premise that the phenomenon can be described by a dimensionally correct equation among the relevant variables. In brief, dimensional analysis is based on the Buckingham π-Theorem which utilizes the classical principle of similarity: if an equation is dimensionally homogeneous, it can be reduced to a relationship among a complete set of dimensionless products called π's. The set is complete when each dimensionless group is independent of the other groups and every dimensionless product is a product of powers of dimensionless products in the set. It is very important that all relevant variables be identified and included in the analysis. Usually, dimensional analysis enables the derivation of scaling groups from variables that do not appear among those governing equations forming the basis for inspectional analysis.

3.4.1.2 Inspectional Analysis

Inspectional analysis was discussed by Geertsma, Croes, and Schwartz[50] and Craig *et al.*[51] who stated that all relevant partial differential equations, based mainly on the physical laws of matter (mass, momentum, and energy) conservation, must first be formulated to describe the flow process. The equations are then rendered dimensionless, and the dimensionless similarity groups are isolated from the coefficients of the dimensionless equations. The scaling criteria are then determined from the set of dimensionless similarity groups. The chief advantage of inspectional analysis is that the scaling criteria thus obtained have a clear physical meaning, and their function in the process can be readily conceived.

Usually, the number of scaling groups derived from either dimensional analysis or inspectional analysis is too large to implement and satisfy in an experiment. A careful examination of the groups is therefore necessary to discern which groups are more consequential, and the possible error that would be caused by relaxing the remaining groups.

Geertsma, Croes and Schwarz[50] showed in their work that the number of groups from dimensional analysis is greater than that from inspectional analysis. Farouq Ali *et al.*[52] pointed out the advantages and disadvantages of both methods and the difficulties in fabricating a properly scaled model.

Rojas[4] used both dimensional and inspectional analyses to derive the scaling criteria for the immiscible carbon dioxide WAG displacement process. With respect to inspectional analysis, the assumptions used by the author for the governing partial differential equations included: the porous medium is homogeneous and isotropic, fluids are immiscible and have small and constant compressibility at reservoir conditions, Darcy's and Fick's laws are valid, flow rates are small enough so that the inertial effects are negligible, the behaviour of oil is Newtonian, relative permeabilities depend on saturation according to the channel flow theory, and the reservoir temperature remains constant during carbon dioxide/water injection. Additionally, it was assumed that three phases may exist: an oleic phase, an aqueous phase, and a carbon dioxide phase, and that there is no transfer of heavy oil components or water to subcritical carbon dioxide.

Rojas[4] observed that the scaling groups derived from inspectional analysis were more flexible when applied towards the realization of the physical model and laboratory experiments. From the work by Geertsma *et al.*[50], the limit on the velocity for Darcy's law to be applicable (Re<0.1) was modified for two-phase flow as follows.

$$v < \frac{20\mu_g(\phi Sg)^{5.5}}{\rho_g\sqrt{kk_{rg}}}$$

For the variables in the experiment, the above inequality presumes that the superficial velocity of carbon dioxide had to be < 2.74 m/d.

It was stated that when the capillary and inertial forces were relaxed and the mass transfer of fluids was taken into account, the resulting scaling groups for the heavy oil displacement process were as follows:

1.	L/b	Geometric factor
2.	L/h	Geometric factor
3.	M_{go}	Mobility ratio of the viscous forces of the vapour and oleic phases
4.	M_{wo}	Mobility ratio of the viscous forces of the aqueous and oleic phases
5.	$\frac{\vec{g}\, k\, \Delta\rho_{og}}{v\mu_g}$	Ratio of gravity to viscous forces of the oleic and vapour phases
6.	$\frac{\vec{g}\, k\Delta\rho_{ow}}{v\mu_w}$	Ratio of gravity to viscous forces of the oleic and aqueous phases
7.	$\frac{V_w^*}{V_g^*}$	Ratio of water to gas slug volumes
8.	$\frac{K_{Tgo}L}{b^2v}$	Ratio of convective time to transverse dispersion time of the vapour and oleic phases
9.	$\frac{K_{Tgw}L}{b^2v}$	Ratio of convective time to transverse dispersion time of the vapour and aqueous phases
10.	$\frac{K_{Tgo}L}{K_{Lgo}b}$	Gas-in-oil dispersion similarity group
11.	$\frac{K_{Tgw}L}{K_{Lgw}b}$	Gas-in-water dispersion similarity group

12.	ϕ	Porosity factor
13.	F_w	Morphology factor

Using these groups as the basic scaling groups, a high-pressure physical model was designed to simulate the process as closely as possible.

Rojas[4] stated that unrealistically large models and extended run times would result if the process required exact scaling of the transverse and longitudinal dispersion groups together with the geometric and chemical similarities, and the ratio of viscous-to-gravitational forces. The above-mentioned groups were satisfied at the low velocity (0.18 m/d), with the exception of the lateral dispersion group. At the higher velocity (2.9 m/d), all the groups except the ratio of the viscous-to-gravitational forces were satisfied.

A 20% hydrocarbon pore volume slug size was chosen on the basis of the first run which showed the oil recovery to have reached a plateau when a 20% hydrocarbon pore volume carbon dioxide slug was injected. Also, Wang[25] reported that, based on his experimental results, a 20% hydrocarbon pore volume carbon dioxide slug size was optimal for heavy oil recovery. Considering that the flow velocity in a five-spot pattern varies substantially from near the wellbore to midway between wells, it was difficult to choose the correct superficial velocity to calculate the scaling factor. The formula, $v = \frac{5q}{\sqrt{2}hL}$, which assumes that a reasonable width for calculating an average velocity is one-fifth the distance between wells, was used.[53] Rojas[1,4-5] varied the carbon dioxide and brine superficial velocity from 0.18 to 2.9 m/d, and this wide range of velocities enabled the study of the viscous, diffusive and gravitational forces in the process.

The prototype of the physical model was a quadrant of a five-spot pattern in the Lloydminster district with an area of 6.4 ha (64750 m^2). The model was selected to be as large as physically possible within the restrictions of space and time. The length of the model was arbitrarily chosen to be: $L_M = W_M = 1.5$ ft (0.457 m), and the model thickness was evaluated by using the geometric scaling factor

$$\frac{L_M}{h_M} = \frac{L_P}{h_P}$$

L_M = length of the model = 0.457 m

$$L_P = \text{length of the prototype} = \frac{\sqrt{64750}}{2} = \frac{254.46}{2} = 127.23 \text{ m}$$

$$h_P = \text{thickness of the prototype} = 6.1 \text{ m (from Table 3.1)}$$

$$\therefore \quad h_M = \left(\frac{h}{L}\right)_P \times L_M = \frac{0.457 \text{ m}}{127.23 \text{ m} / 6.1 \text{ m}} = 0.022 \text{ m (2.2 cm)}$$

Some of the important conclusions based on the series of experiments carried out by Rojas[4] were that viscous forces completely dominated the process, mass transfer occurred between carbon dioxide and oil, and the *in situ* emulsification of oil had a stabilizing effect on the water front. The WAG process was quite successful when using a 4:1 WAG ratio for the recovery scheme.

Zhu[6] conducted all of his experiments in the two-dimensional model at 5.5 MPa and at 21 to 23°C, with the exception of two experiments conducted at 2.5 MPa. Different parameters were investigated in this study. It was shown that an initial gas saturation may lead to a decrease in oil recovery, and a mobile gas phase could have an adverse effect on performance. Effect of heterogeneity was tested by positioning a high permeability streak between the injection and production wells. It was found that heterogeneity reduced oil recovery. For experiments involving a preflood of carbon dioxide or nitrogen, the results showed that carbon dioxide was costly and inefficient to use, while nitrogen did not have a major effect on recovery. It was also found that when nitrogen was used instead of carbon dioxide, oil recovery was essentially the waterflood recovery combined with the blowdown recovery due to gas compressibility.

Dyer[7] conducted a variety of experiments at 1.0 and 2.5 MPa in a linear model which was designed to simulate a direct line drive. This model was designed to act as a screening model for the larger, more time-consuming, two-dimensional model. Also, this model was used to differentiate the displacement and mobilization efficiencies by assuming the areal and vertical sweep to be equal to unity.

The linear model was developed by transforming the geometric scaling group of the two-dimensional model to a circular cross-sectional area. L/h is the similarity group used to scale the length-to-height ratio for the model and prototype. This group was used as follows:

$$\frac{(L/h)_M}{(L/h)_P} = \frac{(L/W)_M}{(L/W)_P} = 1$$

The cross-sectional area of the model was equated to the cross-sectional rectangular area of the field, and the equivalent diameter of the linear model was calculated.

$$HW = \frac{\pi}{4} D^2$$

$$\therefore \; D = 2\sqrt{\frac{(HW)}{\pi}}$$

The modified scaling group resulted in the following equation

$$\frac{(L/D)_M}{(L/D)_P} = 1$$

The linear model had a length of 41.5 cm and a diameter of 9.8 cm. It was believed that this system closely approximated the assumption of 100% areal and vertical sweep efficiencies.

Three experiments were conducted to study the effect of the number of slugs for the low pressure WAG process. The cumulative volume of carbon dioxide injected was the same. The first, second and third experiment used one, five, and ten slugs, respectively. The single slug was found to be the least efficient, and resulted in the lowest oil recovery. It was observed that the optimal number of slugs was ten slugs and that the first slug was the most important slug when considering oil recovery.

Five experiments were carried out to study the effect of slug size on oil recovery at low pressure. All of these experiments used a 4:1 WAG ratio with ten slugs at 1.0 MPa and scaled velocity. Slug volumes of 10, 20, 40, 89, and 179% hydrocarbon pore volume were used in the experiments. The optimum slug size was found to be in the range of 20 to 40% hydrocarbon pore volume. This inference was based on the total oil recovery, injection flood life and carbon dioxide requirement. The rise in oil recovery was significant up to the 40% slug size, after which carbon dioxide was utilized inefficiently and gas channelling occurred relatively faster.

Dyer[7] also conducted six runs to determine the combined effect of the WAG ratio and velocity on the process. All these runs involved the injection of 20% hydrocarbon pore volume of carbon dioxide at 1.0 MPa, using WAG ratios of 2:1, 4:1, and 8:1, respectively. Three runs were carried out at a velocity of 0.98 m/d, while the other three were at 0.49 m/d. It was found that the 4:1 WAG ratio resulted in the largest volume of oil produced, for both velocities.

The effect of initial oil viscosity was studied by utilizing two cases of secondary and tertiary recovery involving two different oil samples: 150 mPa.s and 1055 mPa.s. When the secondary recovery mode was compared to the tertiary mode for the 150 mPa.s sample, it was found that the ultimate recovery was the same. The secondary approach recovered 65.0% hydrocarbon pore volume while the tertiary mode recovered 60.7% hydrocarbon pore volume with an additional residual oil recovery of 12.4% residual hydrocarbon pore volume. Additionally, the secondary recovery technique gave better results for the 1055 mPa.s oil sample. In this case, the secondary recovery produced 47% hydrocarbon pore volume while the tertiary recovery produced 38.8% hydrocarbon pore volume with an additional 11.8% residual hydrocarbon pore volume.

It was observed that the overall carbon dioxide requirement was reduced significantly for both the low and high oil viscosity runs, because less gas was injected and more water was present into which the carbon dioxide could dissolve. Based upon these results, at low pressures, the immiscible carbon dioxide WAG process did not yield significant recoveries for the low viscosity oil in either the secondary or the tertiary modes. Table 3.2 is a summary of all the previous immiscible carbon dioxide displacement experiments conducted in the laboratory.

3.4.2 Laboratory Studies of the Huff n' Puff Process

Sankur and Emmanuel[54] conducted laboratory corefloods with a 14° API oil. The first cycle recovered 6 percent of the remaining oil with a carbon dioxide utilization factor of 1.95E+06 sm^3/m^3, whereas the second cycle recovered only half as much oil, 3 %, with three times more carbon dioxide.

Sayegh and Maini[37] conducted a laboratory evaluation of the carbon dioxide huff n' puff process for heavy oil reservoirs. They performed phase behaviour measurements on the reconstituted oil in two series. The first series was completed using carbon dioxide as the carbonating gas, where they observed some oil swelling and a large reduction in the oil

Table 3.2

Summary of Previous Immiscible Carbon Dioxide Displacement Experiments **

Run #	Model Type	Process Description	Model Parameters: Ave Por (%)	Abs Perm (darcies)	Oil Visc (mPa.s)	Water Sat (%)	Oil Sat (%)	Experimental Parameters: Run Press (MPa)	Ave Flow Vel (m/d)	CO2 Vol Inj (HCPV)	CO2 Moles Inj (g-mol)	Results: CO2 Req. (sm3/sm3)	CO2 Ret. (% inj)	Total Recovery (% HCPV)
1a R	TD	0.15 HCPV Waterflood (Tertiary)	43.70	10.1	4681	6.4	93.6	5.50	3.41	0.00	0	0	0.00	1.66
1b R	TD	1 CO2 Slug => 0.33 RHCPV WF & 0.38 m/d CO2	43.70	10.1	4681	7.9	92.1	5.50	3.41	0.04	0.27	37.99	32.41	9.11/9.26
3a R	TD	2.36 HCPV Waterflood (Tertiary)	44.90	10.2	1032	18.5	81.5	5.50	2.27	0.00	0	0	0.00	45.27
3b R	TD	1 CO2 Slug => 1.42 RHCPV WF & 2.22 m/d CO2	44.90	10.2	1032	55.4	44.6	5.50	2.27	0.31	2.08	40.5	62.93	25.26/46.17
4a R	TD	3.10 HCPV Waterflood & Tank Sand (Tertiary)	43.00	10.6	1032	26.4	73.6	5.50	2.31	0.00	0	0	0.00	54.40
4b R	TD	1 CO2 Slug => 1.52 RHCPV WF & 2.31 m/d CO2	43.00	10.6	1032	66.5	33.5	5.50	2.31	0.35	2.08	48.85	32.74	13.24/29.05
5 R	TD	1 CO2 Slug => 2.18 HCPV WF & Tank Sand	44.00	7.4	1032	11.7	88.3	5.50	2.27	0.19	1.4	32.91	36.96	54.97
6 R	TD	1 CO2 Slug => 2.32 HCPV WF	43.14	24.3	1032	11.4	88.6	5.50	0.18	0.20	1.42	47.33	54.19	39.15
7 R	TD	1 CO2 Slug => 0.66 HCPV WF	43.70	15.4	1032	9.9	90.1	5.50	0.20	0.21	1.47	70.31	84.03	26.35
8 R	TD	1 CO2 Slug => 1.90 HCPV WF	45.50	15.4	1032	9.0	91.0	5.50	2.90	0.20	1.53	48.37	25.22	38.31
9 R	TD	1 CO2 Slug => 2.06 HCPV WF & 1.66 m/d CO2	45.67	16.8	1032	9.0	91.1	5.50	1.05	0.20	1.54	55.31	64.76	33.54
10 R	TD	1 CO2 Slug => 2.13 HCPV WF & 0.72 m/d CO2	47.00	17.9	1032	12.3	87.7	5.50	2.32	0.20	1.52	40.35	19.95	45.91
11 R	TD	1.72 HCPV Waterflood	38.74	8.7	1032	11.7	88.3	5.50	0.87	0.00	0	0	0.00	32.39
12 R	TD	1 CO2 Slug => 1.84 HCPV WF & Tank Sand	48.05	4.9	1032	8.1	91.9	5.50	2.90	0.20	1.62	36.27	76.63	50.94
13 R	TD	1:1 WAG (5 CO2 Slugs)	43.52	11.9	1032	12.4	87.6	5.50	1.15	0.16	1.13	38.55	68.85	38.56
14 R	TD	1:1 WAG (10 CO2 Slugs)	41.19	10.9	1032	11.7	88.3	5.50	1.16	0.20	1.35	47.28	48.99	39.42
15 R	TD	3:1 WAG (10 CO2 Slugs)	43.22	11.7	1032	11.1	88.9	5.50	1.16	0.20	1.42	43.72	74.39	42.26
16 R	TD	4:1 WAG (10 CO2 Slugs)	44.40	14.9	1032	11.3	88.7	5.50	1.44	0.20	1.46	39.04	67.54	47.54
17 R	TD	5:1 WAG (10 CO2 Slugs)	42.78	12.4	1032	12.7	87.6	5.50	1.16	0.20	1.4	40.46	53.53	46.44
18 R	TD	6:1 WAG (10 CO2 Slugs)	43.71	14.1	1032	12.2	87.8	5.50	1.47	0.20	1.43	43.29	61.34	43.25
19aR	TD	1.71 HCPV Waterflood (Tertiary)	44.70	14.8	1032	14.3	85.7	5.50	1.43	0.00	0	0	0.00	35.19
19bR	TD	4:1 WAG (10 CO2 Slugs)	44.70	14.8	1032	44.5	55.6	5.50	1.43	0.20	1.42	38.13	63.73	13.53/20.87
20aR	TD	1.63 HCPV Waterflood (Tertiary)	44.91	14.8	1032	10.1	89.9	5.50	1.44	0.00	0	0	0.00	35.52
20bR	TD	1:1 WAG (10 CO2 Slugs)	44.91	14.8	1032	42.0	58.0	5.50	1.44	0.20	1.54	39.91	64.87	12.47/19.34
21aR	TD	1.66 HCPV Waterflood (Tertiary)	43.15	9.3	1032	11.9	88.1	5.50	0.88	0.00	0	0	0.00	33.75
21bR	TD	6:1 WAG (10 CO2 Slugs)	43.15	9.3	1032	41.6	58.4	5.50	0.88	0.20	1.41	40.11	50.36	12.56/18.95
22aR	TD	0.85 HCPV Waterflood (Tertiary)	41.99	9.7	4681	11.0	89.0	5.50	0.87	0.00	0	0	0.00	17.11
22bR	TD	4:1 WAG (10 CO2 Slugs)	41.99	9.7	4681	26.2	73.8	5.50	0.87	0.20	1.4	68.18	45.38	10.57/12.75
23 R	TD	4:1 WAG (10 CO2 Slugs)	42.14	9.3	4681	10.9	89.1	5.50	0.87	0.20	1.39	83.58	75.21	22.19
24 R	TD	1 CO2 Slug => 1.38 HCPV WF	44.06	11.5	4681	10.9	89.1	5.50	1.16	0.20	1.45	81.55	31.42	22.80

Table 3.2 (continued)
Summary of Previous Immiscible Carbon Dioxide Displacement Experiments **

Run #	Model Type	Process Description	Model Parameters					Experimental Parameters				Results		
			Ave Por (%)	Abs Perm (darcies)	Oil Visc (mPa.s)	Water Sat (%)	Oil Sat (%)	Run Press (MPa)	Ave Flow Vel (m/d)	CO2 Vol Inj (HCPV)	CO2 Moles Inj (g-mol)	CO2 Req. (sm3/sm3)	CO2 Ret. (% inj)	Total Recovery (% HCPV)
25 R	TD	4:1 WAG (10 CO2 Slugs) & Tank Sand	43.21	4.5	1032	12.2	87.8	5.50	0.44	0.20	1.4	42.21	94.73	43.93
2a Z	TD	1.70 HCPV Waterflood (Tertiary)	37.55	8.5	1032	10.3	89.7	5.50	0.78	0.00	0	0	0.00	32.46
2b Z	TD	1 CO2 Slug => 2.44 RHCPV WF	37.55	8.5	1032	39.4	60.6	5.50	0.78	0.20	1.27	47.87	35.70	10.77/15.95
3a Z	TD	1.77 HCPV Waterflood (Tertiary)	39.81	10.0	1032	10.2	89.8	5.50	0.78	0.00	0	0	0.00	29.57
3b Z	TD	4:1 WAG (10 CO2 Slugs)	39.81	10.0	1032	36.8	63.2	5.50	0.78	0.20	1.36	51.62	37.41	6.78/9.63
4 Z	TD	4:1 WAG (10 N2 Slugs)	46.51	11.2	1032	18.5	81.5	5.50	1.04	0.20 *	0.81 *	33.9 *	61.74 *	33.00
5 Z	TD	4:1 WAG (10 N2 Slugs)	40.40	12.0	1116	7.0	93.0	5.50	1.04	0.20 *	0.80 *	34.3 *	22.97 *	32.50
6 Z	TD	4:1 WAG (18 N2 Slugs)	47.04	15.8	1116	17.2	82.9	5.50	1.29	0.21 *	0.83 *	35.3 *	14.09 *	31.60
7 Z	TD	3:1 WAG (10 N2 Slugs)	41.85	16.8	1116	9.0	91.0	5.50	1.55	0.20 *	0.81 *	34.1 *	17.93 *	32.70
8a Z	TD	1.00 HCPV Waterflood (Tertiary)	38.55	9.7	1116	8.4	91.6	5.50	0.78	0.00	0	0	0.00	25.32
8b Z	TD	4:1 WAG (10 N2 Slugs)	38.55	9.7	1116	31.6	68.4	5.50	0.78	0.20 *	0.76 *	63.5 *	36.97 *	6.26/8.38
9 Z	TD	4:1 WAG (10 CO2 Slugs) & 1.32 HCPV N2 Preflush	42.08	17.6	1116	7.9	92.1	5.50	1.55	0.20	1.65	48.16	51.51	43.70
10 Z	TD	4:1 WAG (10 CO2 Slugs) & 4.33 HCPV CO2 Preflush	39.87	15.5	1116	7.5	92.5	5.50	1.29	4.53	31.4	758.9	13.28	58.20
11 Z	TD	4:1 WAG (10 CO2 Slugs) & 4.27 HCPV CO2 Preflush	40.85	17.4	1116	8.9	91.1	5.50	0.32	4.47	31.25	710.1	0.00	61.20
12 Z	TD	1 CO2 Slug => 2.48 HCPV WF	40.48	12.4	1116	7.6	92.4	5.50	2.07	0.20	1.43	60.3	23.76	33.00
13 Z	TD	4:1 WAG (10 CO2 Slugs)	38.71	5.3	1116	9.7	90.3	5.50	2.59	0.20	1.33	54.9	37.05	35.90
14 Z	TD	4:1 WAG (10 CO2 Slugs)	43.15	16.2	1116	10.1	89.9	5.50	1.55	0.40	2.94	89.2	30.22	43.70
15 Z	TD	0.1 HCPV CO2 => 0.1 HCPV N2 => 1.79 HCPV WF	41.12	14.9	1116	9.4	90.6	5.50	1.55	0.10	0.7	27.5	36.78	35.40
16 Z	TD	4:1 WAG (10 CO2 Slugs)	39.26	14.3	1116	9.5	90.5	5.50	1.55	0.20	1.34	45.1	45.82	43.00
17 Z	TD	4:1 WAG (9 CO2 Slugs)	42.31	18.4	1116	10.1	89.9	5.50	1.55	0.10	0.73	27.9	74.11	35.40
18 Z	TD	4:1 WAG (10 CO2 Slugs) & High Perm Streak	38.80	18.1	2107	11.5	88.5	5.50	1.55	0.20	1.29	64.4	45.78	30.30
19 Z	TD	4:1 WAG (10 CO2 Slugs) & Parallel Beds	37.24	18.6	2107	7.5	92.5	5.50	1.55	0.20	1.3	85.2	50.13	22.80
20 Z	TD	4:1 WAG (10 CO2 Slugs) & Parallel Beds	37.37	16.4	1101	11.3	88.8	5.50	1.55	0.20	1.25	63.9	58.99	30.30
21 Z	TD	4:1 WAG (10 CO2 Slugs) & High Perm Streak	38.69	15.8	1101	10.3	89.7	5.50	1.55	0.20	1.31	67.7	51.95	28.80
22 Z	TD	4:1 WAG (9 CO2 Slugs)	40.27	13.3	1101	7.1	92.9	2.50	1.29	0.10	0.66	36.9	62.65	25.70
23 Z	TD	4:1 WAG (10 CO2 Slugs)	41.16	17.4	1101	9.6	90.4	2.50	1.55	0.20	1.26	55.8	46.22	34.90
24 Z	TD	4:1 WAG (10 CO2 Slugs)	41.39	15.4	1233	8.9	91.1	5.50	1.55	0.20	1.42	68.5	98.17	28.20
25 Z	TD	4:1 WAG (10 CO2 Slugs)	40.81	8.2	1092	10.1	89.9	5.50	0.78	0.20	1.38	72.1	84.93	26.80

Table 3.2 (continued)

Summary of Previous Immiscible Carbon Dioxide Displacement Experiments **

Run #	Model Type	Process Description	Model Parameters					Experimental Parameters				Results		
			Ave Por (%)	Abs Perm (darcies)	Oil Visc (mPa.s)	Water Sat (%)	Oil Sat (%)	Run Press (MPa)	Ave Flow Vel (m/d)	CO2 Vol Inj (HCPV)	CO2 Moles Inj (g-mol)	CO2 Req. (sm3/sm3)	CO2 Ret. (% inj)	Total Recovery (% HCPV)
26aZ	TD	0.62 HCPV Waterflood (Tertiary)	40.40	11.2	1092	10.0	90.0	5.50	1.03	0.00	0	0	0.00	15.62
26bZ	TD	4:1 WAG (10 CO2 Slugs)	40.40	11.2	1092	24.1	75.9	5.50	1.03	0.20	1.37	68.5	90.34	18.55/21.98
27aZ	TD	1.20 HCPV Waterflood (Tertiary)	42.11	17.7	1092	10.3	89.7	5.50	1.55	0.00	0	0	0.00	21.78
27bZ	TD	4:1 WAG (10 CO2 Slugs)	42.11	17.7	1092	29.9	70.1	5.50	1.55	0.20	1.31	72.1	96.52	13.94/17.82
28 Z	TD	4:1 WAG (10 CO2 Slugs) & Sgi = 13.20% N2	39.03	11.7	1092	10.3	76.5	5.50	1.29	0.23	1.29	64.02	67.66	33.10
29 Z	TD	4:1 WAG (7 CO2 Slugs) & Sgi = 11.29% N2	42.72	16.7	1092	12.4	75.7	5.50	1.55	0.21	1.27	91.77	67.17	21.10
30 Z	TD	4:1 WAG (10 CO2 Slugs) & Sgi = 15.86% N2	40.53	16.6	1092	9.8	74.6	2.50	1.55	0.20	1.27	67.3	69.69	31.60
31 Z	TD	4:1 WAG (11 CO2 Slugs) & Sgi = 14.62% N2	41.08	13.3	1092	11.0	74.3	2.50	1.29	0.20	1.28	95.9	78.54	32.00
32 Z	TD	4:1 WAG (10 CO2 Slugs) & Sgi = 3.97% N2 (PB)	35.86	10.2	1092	8.5	87.5	2.50	1.03	0.20	1.26	61.5	87.53	32.20
33 Z	TD	4:1 WAG (10 CO2 Slugs) & Sgi = 15.29% N2 (HS)	37.59	18.9	1092	10.6	74.1	2.50	2.59	0.20	1.28	66.7	50.32	33.10
1 D	LC	1.92 HCPV Waterflood	35.00	11.1	1059	7.0	93.0	1.00	0.98	0.00	0	0	0.0	39.14
2 D	LC	1.44 HCPV Waterflood	35.00	5.6	1059	10.0	90.0	1.00	0.25	0.00	0	0	0.0	37.58
3 D	LC	4:1 WAG Process (10-Slugs)	36.60	10.7	1055	12.7	87.3	1.00	0.98	1.79	0.77	30.49	13.8	60.98
4 D	LC	4:1 WAG Process (10-Slugs)	36.30	11.5	1055	10.8	89.3	1.00	0.98	0.89	0.39	17.37	10.3	55.54
5 D	LC	4:1 WAG Process (5-Slugs)	35.63	10.8	1055	9.9	90.1	1.00	0.98	0.89	0.39	17.1	2.9	53.86
6 D	LC	4:1 WAG Process (1-Slug)	34.10	12.7	1055	10.8	89.2	1.00	0.98	0.89	0.39	24.85	6.0	46.37
7 D	LC	4:1 WAG Process (10-Slugs)	34.80	15.8	1055	9.4	90.6	1.00	0.98	0.20	0.09	4.44	8.4	46.97
8a D	LC	2.11 HCPV Waterflood (Tertiary)	37.05	11.4	1055	10.3	89.7	1.00	0.98	0.00	0	0	0.0	38.81
8b D	LC	4:1 WAG Process (10 CO2 Slugs)	37.05	11.4	1055	45.1	54.9	1.00	0.98	0.20	0.05	2.77	55.6	7.22/11.79
9 D	LC	4:1 WAG Process (10-Slugs)	36.73	12.7	1055	10.0	90.0	1.00	0.98	0.10	0.04	2.34	6.0	44.64
10 D	LC	4:1 WAG Process (10-Slugs)	35.77	11.0	1055	11.1	88.9	1.00	0.98	0.40	0.17	8.59	9.2	49.81
11 D	LC	8:1 WAG Process (10-Slugs)	38.28	14.0	1055	10.1	90.0	1.00	0.98	0.20	0.09	4.59	8.0	45.58
12 D	LC	2:1 WAG Process (10-Slugs)	38.40	16.2	1055	9.2	90.8	1.00	0.98	0.20	0.09	5.18	15.6	40.87
13 D	LC	4:1 WAG Process (10-Slugs) v/2	36.22	12.1	1055.3	9.5	90.5	1.00	0.49	0.20	0.09	4.63	53.31	44.92
14 D	LC	8:1 WAG Process (10-Slugs) v/2	36.93	12.1	1055.3	9.8	90.2	1.00	0.49	0.20	0.09	4.65	57.78	44.89
15 D	LC	2:1 WAG Process (10-Slugs) v/2	36.57	12.1	1055.3	9.7	90.3	1.00	0.49	0.20	0.09	4.74	23.51	43.97
16 D	LC	4:1 WAG Process (10-Slugs)	34.8	9.0	1059	20.9	79.1	2.50	0.98	0.64	0.75	29.71	93.91	52.73
17 D	LC	4:1 WAG Process (10-Slugs)	37.70	12.3	1055	10.8	89.2	2.50	0.98	0.20	0.26	12.64	20.46	48.02
18 D	LC	4:1 WAG Process (10-Slugs)	33.30	5.9	1059	10.3	89.7	5.50	0.98	0.21	0.74	43.43	100.00	46.81

Table 3.2 (continued)
Summary of Previous Immiscible Carbon Dioxide Displacement Experiments **

Run #	Model Type	Process Description	Model Parameters: Ave Por (%)	Abs Perm (darcies)	Oil Visc (mPa.s)	Water Sat (%)	Oil Sat (%)	Experimental Parameters: Run Press (MPa)	Ave Flow Vel (m/d)	CO2 Vol Inj (HCPV)	CO2 Moles Inj (g-mol)	Results: CO2 Req. (sm3/sm3)	CO2 Ret. (% inj)	Total Recovery (% HCPV)
19 D	LC	4:1 WAG Process (10-Slugs)	34.40	12.4	1059	10.8	89.2	5.50	0.98	0.20	0.7	44.76	98.90	42.88
20 D	LC	4:1 WAG Process (10-Slugs)	35.77	12.5	1055	10.7	89.3	5.50	0.98	0.20	0.78	37.76	80.04	49.07
21 D	LC	4:1 WAG Process (10-Slugs)	36.69	15.1	1055	6.1	94.0	5.50	0.98	0.10	0.42	18.9	68.21	49.02
22 D	LC	4:1 WAG Process, Wainwright	36.67	11.4	150	11.8	88.2	1.00	0.98	0.20	0.09	3.43	6.07	64.96
23aD	LC	2.29 HCPV Waterflood, Wainwright (Tertiary)	36.22	11.5	150	13.0	87.1	1.00	0.98	0.00	0	0	0.00	60.71
23bD	LC	4:1 WAG (10 CO2 Slugs), Wainwright	36.22	11.5	150	65.8	34.2	1.00	0.98	0.20	0.05	1.17	12.52	5.01/12.4
# 1D	TD	4:1 WAG (10 CO2 Slugs) Senlac	43.10	7.6	3295	13.2	86.8	2.50	0.78	0.61	1.41	45.38	48.91	40.86
# 2D	TD	4:1 WAG (10 CO2 Slugs) Senlac	41.50	7.4	3295	9.9	90.1	4.10	0.78	0.33	1.41	40.2	28.68	46.26
# 3D	TD	4:1 WAG (10 CO2 Slugs) Aberfeldy	40.59	13.3	1055	8.7	91.3	1.00	0.83	0.20	0.16	4.83	65.99	43.30

Abbreviations and Symbols

Tank Sand = Cleaned Aberfeldy Tank Sand
Continuous CO2 => WF : A Single CO2 Slug Followed by a Waterflood
High Perm Streak (HS) : Diagonal Bed of High Permeability Glass Beads
Parallel Beds (PB) : Layer of Sand and a Layer of Glass Beads
* : Refers to Nitrogen Rather than Carbon Dioxide
? : Value is Highly Questionable due to Equipment Problems

" R " : Gonzalo Rojas (1983 - 1985)
" Z " : Tao Zhu (1985 - 1987)
" D " : Steve Dyer (1987 - 1989)

WF = Waterflood
CO2 = Carbon Dioxide Gas
N2 = Nitrogen Gas
Sgi = Initial N2 Gas Saturation

CO2 Required = Total CO2 Injected (std. cond.) / Total Oil Produced
CO2 Retained = Percentage of Total CO2 Injected & Not Produced
Total Recovery = Process Recovery + Waterflood Recovery + Blowdown Recovery

T-REC: HCPV Basis/RHCPV Basis & RHCPV = oil remaining after WF

Aberfeldy Solubility:

	Rso (sm3/m3)	Rsw (sm3/m3)	
@ 1.00 MPa	10.1	4.97	HCPV Required to Saturate= { Rso + [Rsw x (1/Soi - 1)] } x 0.096089
@ 2.50 MPa	26.9	10.74	HCPV Required to Saturate= { Rso + [Rsw x (1/Soi - 1)] } x 0.034584
@ 5.50 MPa	68.5	19.91	HCPV Required to Saturate= { Rso + [Rsw x (1/Soi - 1)] } x 0.010791

** Note : All the data is taken from Ref. No. 7.

viscosity. Carbon dioxide was found to have been retained preferentially to methane during the liberation phase. The second series was accomplished using a 1:3 mole ratio of methane/carbon dioxide, simulating the use of recycled gas in the huff n' puff process. These results showed that methane diminished the efficiency of carbon dioxide as a stimulating agent due to its lower solubility and smaller viscosity reduction. Because of the preferential retention of carbon dioxide by the oil, low viscosities were maintained during liberation and thus viscosity reduction played an important role in enhancing oil production.

Monger, Ramos, and Thomas[8] carried out laboratory experiments of the carbon dioxide huff n' puff process for enhanced recovery of light crude oil from watered-out Berea cores, with the objective of highlighting the favourable performance of this process in pressure depleted reservoirs by concentrating on the immiscible recovery of light oil by gaseous carbon dioxide in the laboratory. Their laboratory results suggested that carbon dioxide huff n' puff was more favourable at lower pressures, which is a result of the larger reservoir space occupied by a unit mass of carbon dioxide.

3.4.3 Numerical Simulation Studies of Heavy Oil Production by Carbon Dioxide Injection

The complexity of displacement mechanisms involved in the carbon dioxide injection process prevents any accurate prediction of reservoir performance by empirical means. Previously, adequate analysis of field response relied solely on information obtained from physical studies. However, proper scaling of displacement processes in laboratory models is difficult to achieve. Thus, considerable effort has been devoted to developing numerical models whose results accurately parallel the physical processes active in the reservoir. Two reservoir simulator approaches used in connection with carbon dioxide flooding are:

1. black oil modelling, and
2. compositional modelling.

It is important to note that the simulators are not always able to model completely all the forces that exist in a displacement process.[15]

Nearly all reservoir simulation applications are formulated on the basis of either the conservation of mass or heat in a system that exists in a fixed space and time boundary, and the equations that describe the flow in a porous media.

A compositional model is one where mass balances are performed over each individual component, either in a single-phase or a multiphase flow model. When there are two (or more) components: a nonvolatile (oil) and a volatile (gas) component in the system, in either a single-phase or multiphase model, the simulation is known as black oil modelling. Black oil models are capable of simulating systems where oil, water, and carbon dioxide are present in all proportions. But, if a fourth fluid is present in substantial volume, this method is not suitable as it is unable to account for the mixing of gases.

Stright, Aziz, Settari, and Starratt[55] presented the numerical modelling results of a single well test for a reservoir containing bottom water. In order to improve the carbon dioxide/oil contacting efficiency, carbon dioxide was injected at the oil-water contact. The well was then produced after a 27-day soak period. They concluded that cyclic carbon dioxide injection in bottom water reservoirs was not a feasible process due to efficiency loss. Instead, a slug displacement scheme was recommended.

Reid and Robinson[13], using a three-dimensional, three-phase simulator, modelled the Lick Creek Meakin project. The main operating process was alternating injection of carbon dioxide and water. In addition, cyclic stimulation of the production wells was considered. The simulation results indicated that carbon dioxide stimulation of the production wells prior to the WAG process would improve the rate response, reduce the WOR, and increase carbon dioxide coverage of the reservoir.

Klins and Farouq Ali[56] performed a "black oil type" simulation study of the immiscible carbon dioxide WAG process, and reached the conclusion that this process could lead to an incremental oil recovery of up to 30% over a waterflood. The main features of their numerical model included: no diffusional mixing, non-volatile liquids, and thermodynamic equilibrium between phases. Their results showed that the process efficiency depended on oil viscosity, oil saturation and process operating pressure range. Rojas[4] and Rojas and Farouq Ali[5] reported similar simulation results for laboratory studies.

Spivak and Chima[48] used an equation-of-state compositional simulator for their study of the mechanism of immiscible carbon dioxide injection in heavy oil reservoirs in the Wilmington field, California. The simulator results showed a strong tendency for the gas to override. They concluded that the immiscible carbon dioxide drive can be looked upon as a process of viscosity reduction followed by waterflooding of the less viscous oil. They also inferred that the presence of nitrogen in the injected gas was not detrimental to the recovery performance of the process. The simulator did not consider the effect of dispersive forces and carbon dioxide-induced viscous fingers on oil recovery. Mayer, Earlougher Sr., Spivak, and Costa[57] tried to understand the displacement mechanism by matching simulator results with core floods. Their results indicated that the incremental recovery was more than could be accounted for by the oil viscosity reduction and the crude oil swelling. Spivak, Garrison, and Nguyen[58] conducted several simulation studies on the Tar Zone, Fault Block V, Wilmington Field, California. Due to the presence of nitrogen in the field, a compositional simulator with a minimum of four components, (oil, carbon dioxide, nitrogen, and hydrocarbon gas (mainly methane)) was needed for rigorous simulation of the immiscible process. It was concluded that gravity override was an important mechanism in the Tar V immiscible carbon dioxide project. In addition, a small, continuous water channel between an injector and a producer would lead to rapid gas breakthrough at the producer with very little of the oil recovered.

Denoyelle and Lemonnier[59] presented a new approach to the simulation of the huff n' puff technique by using the concept of relative permeability hysteresis. They used a general purpose compositional simulator. Their first study was of a watered-out light oil reservoir. The simulator model was validated by a successful history match from the production data of the huff n' puff process. Another study was that of a heavy oil reservoir with no water production, where a history match of three consecutive cycles was obtained. From the performance prediction conducted for additional cycles, a number of runs were performed and the results showed that for a heavy oil, gas injectivity and oil productivity may increase with the number of cycles; higher oil productivity was obtained with short cycles than with long ones. For both reservoirs, the recovery process was of the immiscible type and the relative permeability hysteresis was the main cause for incremental oil production.

Monger *et al.*[8], using a commercial, three-phase, three-dimensional, black-oil, fully-implicit reservoir simulator, tried to determine the effect of increasing the amount of carbon dioxide injected. They found that the process efficiency declined with increasing slug size.

3.4.4 Immiscible Carbon Dioxide Field Projects

3.4.4.1 Wilmington Project

The Wilmington Tar Zone[36,48,58], in the Los Angeles Basin, California, is one of the successful producing oilfields that have used the immiscible carbon dioxide WAG process to enhance the recovery of the highly viscous crude oil. The injection project was started in

March 1982 to establish the applicability of immiscible carbon dioxide displacement as a tertiary recovery mechanism. Prior to this, the field project had been under waterflood since 1961. The gas injected initially was a mixture of 85% carbon dioxide and 15% nitrogen. The produced gas was recycled, compressed, and re-injected. The presence of nitrogen was deemed to cause several complications. When using a mixture of carbon dioxide and nitrogen, nitrogen reduced the solubility of carbon dioxide in oil according to the law of partial pressures. On the other hand, the presence of nitrogen, which was insoluble in oil, resulted in trapping of the free nitrogen by the injected water, which, in turn, would have resulted in a lower residual oil saturation. The incremental recovery for the "ideal" immiscible carbon dioxide process was 9.8% original oil-in-place. The cumulative production from August 1982-1987 for the base waterflood was 264,000 stock-tank m^3, and the tertiary incremental oil at the end of August 1987 was 77,590 stock-tank m^3. The theoretical carbon dioxide requirement per sm^3 of tertiary oil was 603.8 sm^3.

3.4.4.2 Bati Raman Project

The Bati Raman[60,61] heavy oil field in Turkey, is considered to be an ideal candidate reservoir for the immiscible carbon dioxide process. Based on a comprehensive laboratory and engineering study, and the economic constraints, Issever, Pamir, and Tirek[61] initiated an immiscible carbon dioxide flood in the field. The planned huff n' puff was converted into a carbon dioxide flood as the gas could not be confined within the region surrounding the wellbore. It was found that the production wells benefited from gas injection with improved oil characteristics and oil production, while the gas production stabilized for the duration of the five year operation. Promising production results encouraged the expansion of the project and the application strategy was changed accordingly. The amount of carbon dioxide required to produce one sm^3 of incremental oil was 801.9 sm^3.

3.4.4.3 Lick Creek Project

The Lick Creek Meakin Sand project[13], in Arkansas, demonstrated the feasibility of the immiscible WAG process for the recovery of oil from thin, heavy-oil sands. Injection of a 40 percent hydrocarbon pore volume slug of carbon dioxide on a 1:1 WAG ratio was accomplished in three phases. The first phase involved cyclic carbon dioxide injection into all the producers and many of the injectors which helped increase the reservoir pressure and allowed wells to flow naturally. The second phase involved injection of large volumes of carbon dioxide into the permanent injectors. The third phase consisted of WAG injection.

This process proved to be very successful, and proved the viability of the immiscible carbon dioxide/waterflood process in thin, heavy-oil sands.

3.4.4.4 Hansford Marmation Project

The Hansford Marmation project[62] was initiated in Hansford County, Texas, in mid 1980. Carbon dioxide was used to repressurize the depleted reservoir and although the time taken to repressurize was longer than with water, the free gas present helped to distribute the carbon dioxide, permitting contact with more of the original oil-in-place than would have been the case by a miscible displacement. During the start-up, the reservoir pressure was a low 1.72 MPa. Immiscible injection of carbon dioxide raised the pressure to near the miscible pressure after which the recycled gas was injected at a predetermined WAG ratio. The results of the project showed that there was an increase in production from 30 to 87.5 m^3 of oil per day and incremental recovery from carbon dioxide injection of approximately 15.6% of the original oil-in-place.

3.4.4.5 Hilly Upland Project

The Hilly Upland pilot project[63] showed that low permeability did not prevent the injection of fluids. It also showed that when water cannot be injected at economic rates to repressurize a reservoir or to displace the solvent slug, carbon dioxide could be used instead. This pilot showed that even though miscibility was attained in the near wellbore region of the injector, the swelling of the oil, the viscosity reduction and the increase in reservoir energy due to carbon dioxide injection resulted in an estimated 5% original oil-in-place incremental recovery.

3.4.5 Huff n' Puff Field Scale Projects

As mentioned previously, the immiscible huff n' puff well stimulations appear to be gaining in popularity due to their ease of operation and their relatively quick payout. Some of the projects are discussed below.

3.4.5.1 Appalachian Basin

Carbon dioxide huff n' puff field tests were completed on 65 wells in a pressure depleted Appalachian basin[8] in eastern Kentucky which indicated the economic viability for light oil recovery. The field tests targeted the Appalachian field because of the low permeability formation and disappointing pilot field results. The rods were first pulled from the wells and large volumes of carbon dioxide were injected down the tubing at high flow rates. The wells were then shut-in for approximately one week, after which, they were placed back on production. The response was a large increase in oil production which extended for 15 to 48 months, after which, production returned to the original decline curve. The resulting low carbon dioxide utilization of about 0.18 sm^3/m^3 proved the economic feasibility of huff n' puff process in light oil reservoirs. The field test results suggested that the process response improved with thicker pay, that carbon dioxide reduced the water cut, and that a second cycle recovered additional oil.

3.4.5.2 Paradis Field

Texaco tested the carbon dioxide huff n' puff process in one of the eleven wells in five fields in South Lousiana[29], during 1984 and 1985. The results of this test, west of New Orleans, in the Paradis Main Pay Sand, Reservoir T, indicated that cyclic use of carbon dioxide was effective. In this case, two cycles were utilized. In the first cycle, 5.09E+5 m^3 of carbon dioxide was injected over a three-day period in March 1984 followed by a three-week soak. After the well was returned to production, the initial rate was 23.8 m^3 of oil per day as compared to 3.65 m^3 of oil per day prior to the test. This well produced 1431 m^3 of oil in excess of the base decline curve prior to receiving an additional 5.95E+5 m^3 of carbon dioxide over a five-day period. After the well was back in production, it produced 36.3 m^3 of oil per day. This resulted in a net utilization factor of only 0.35 m^3/m^3. This test showed that carbon dioxide will finger further into the reservoir when the injection rate is faster, thus contacting more oil.

In conclusion, the carbon dioxide huff n' puff process is a promising enhanced recovery process for both the heavy oil and light oil reservoirs. Some of the important factors that may enhance the application of this process include larger reservoir slug volume, soak period, thicker interval, and lower prior water cut. Laboratory and field results indicate that a second cycle of carbon dioxide injection can recover additional incremental recovery, with a slight reduction in efficiency.[10,29]

4. EXPERIMENTAL APPARATUS and PROCEDURE

The previous chapter presented the details regarding the two physical models, namely the two-dimensional model and the linear model as well as the procedures used to scale the two. This chapter presents the apparatus and materials utilized in the experiments, and the general procedure that was followed in conducting an experiment. Figure 4.1 is a schematic of the experimental model.

4.1 Fluids and Porous Medium

4.1.1 Fluids

The oil used in the experiments was from the Aberfeldy reservoir in Lloydminster. The viscosity of the oil was initially in the 1000 to 4000 mPa.s range, and was later diluted to a scaled viscosity of approximately 1046 mPa.s using a conventional light oil (FAXAM-100). The density of the oil was determined to be 932.4 kg/m^3 and the molecular weight of the oil was calculated to be 424 kg/k.mol. These calculations are included in Appendix A.

The brine used was also from the Aberfeldy reservoir. When the original supply of reservoir brine was used up, simulated brine was prepared for the subsequent experiments. In some of the experiments, "live oil" was used. Live oil is normally referred to as gas-in-solution. The live oil viscosity is calculated by using the correlation of Puttagunta, Singh and Cooper.[65] This calculation is presented in Appendix B.

4.1.1.1 Live Oil Sample Preparation

The apparatus designed to produce a live oil from dead oil in the laboratory is shown in Fig. 4.2. The whole system occupied a small confined area and the oil was prepared without many complications.

A stainless steel cylinder which had a capacity of 3.78 liters was used as a mixing chamber. The inlet at the top had two ports: one was connected to the methane tank and the other to the oil line from which the oil entered the mixing chamber. The methane was supplied constantly, and was maintained at the required experimental pressure. The dead oil, which had to be made live, was first pumped from the oil tank to the mixing chamber. The oil was then circulated from the bottom of the mixing chamber to the top through a two-way

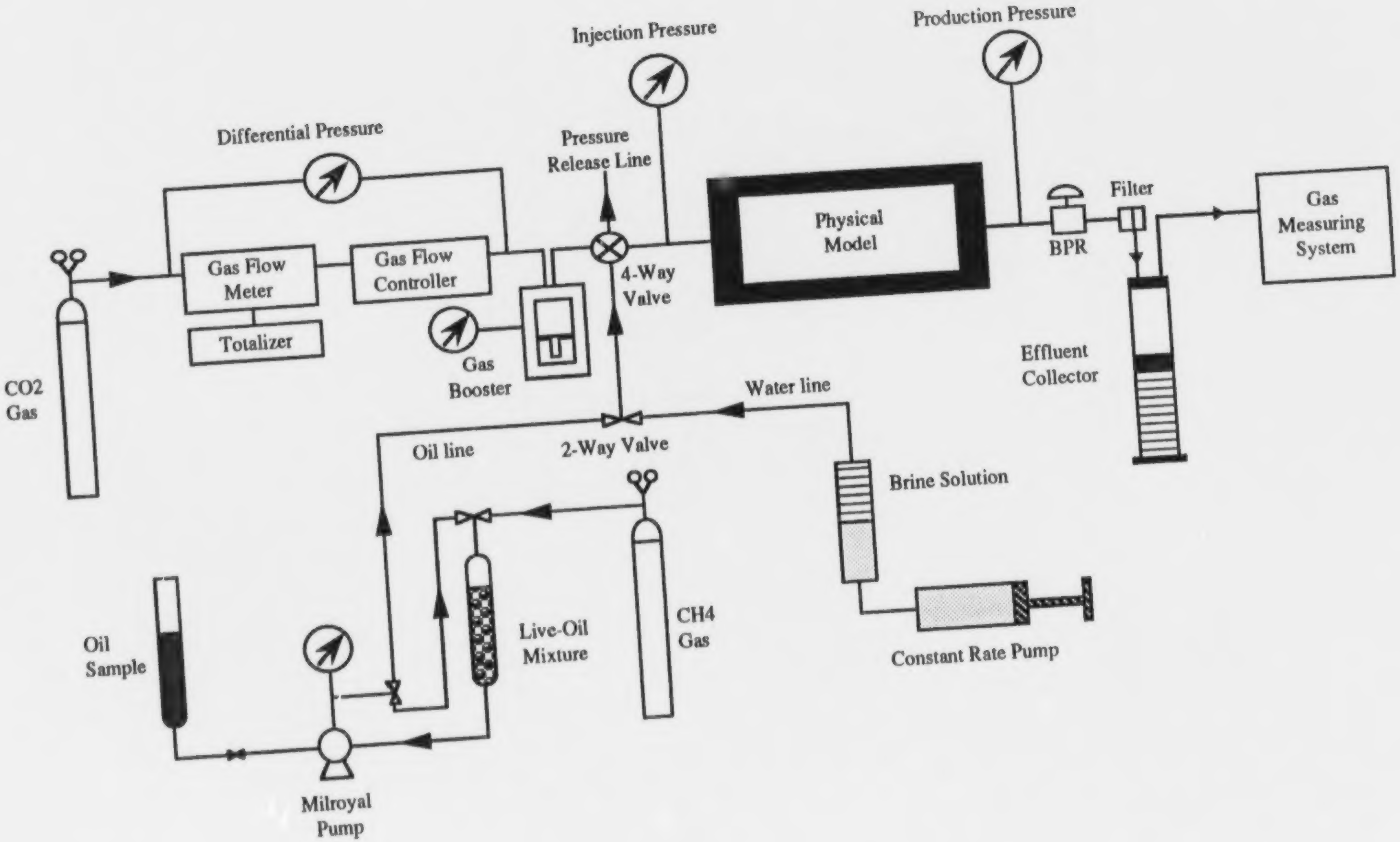


Figure 4.1: Schematic of the Physical Model Apparatus.

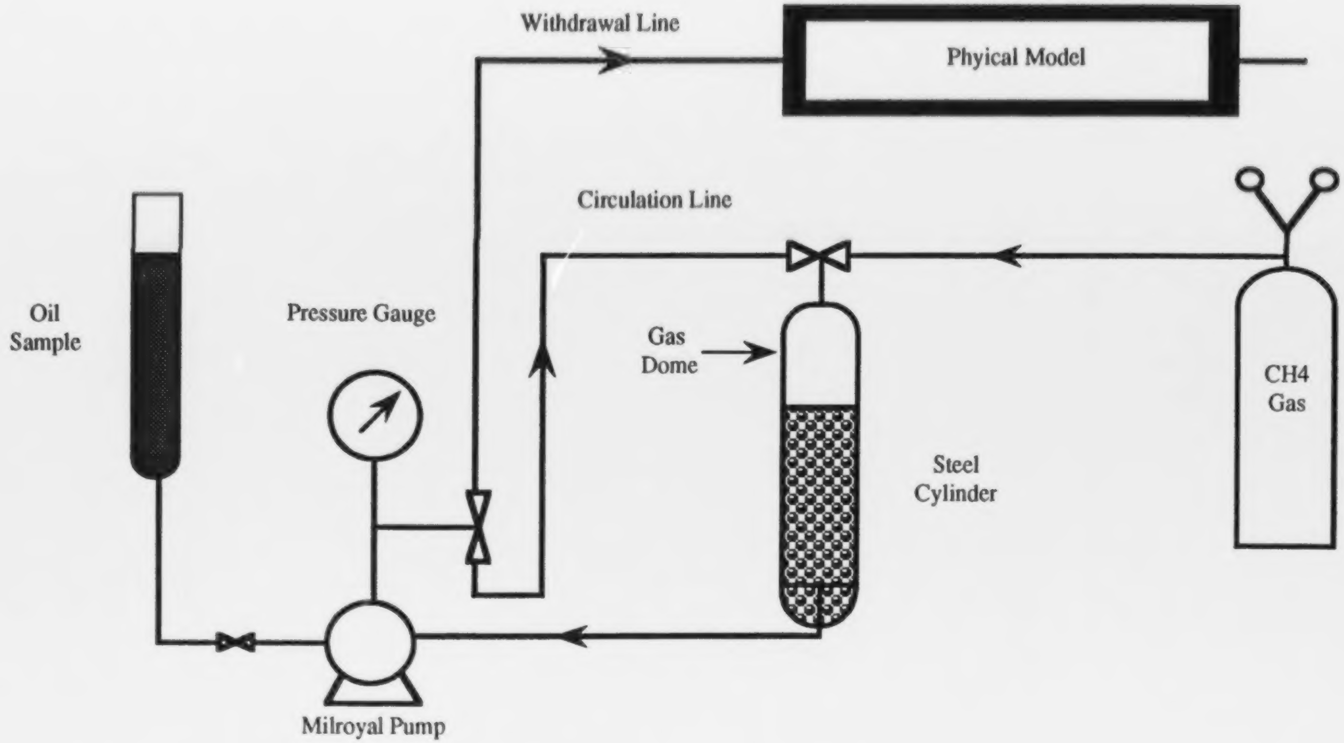


Figure 4.2 : Schematic of the Test Oil Saturated with Methane.

valve using a positive displacement Milroyal pump.

When the oil mixture reached the maximum gas-oil ratio at the experimental pressure, it was mixed for a period of time, the average time approximately being three days until a uniform oil sample was obtained and stabilized. The oil was now ready for the experiment. First it was withdrawn from the bottom of the mixing chamber, and injected directly into the model reservoir. This provided an oil-saturated porous medium at a pressure greater than the experimental pressure—preventing the dissolved gas from coming out of solution.

The gas solubility could be calculated by mixing a known volume of oil and gas in an enclosed system. To calculate the solubility, the volume of gas being liberated when the pressure was decreased was determined. Another method of calculating the solubility is to measure the volume of gas that will dissolve in a given stock-tank crude when the pressure was increased.[66]

4.1.2 Porous Medium

The porous medium for the model reservoir consisted of the Aberfeldy reservoir sand when available. Alternatively, Ottawa silica sand of comparable grain size (Mesh size #70 to 140) was used. All the experiments were conducted at room temperature (23°C). Both the two-dimensional model and the linear model utilized the same oil, brine and sand as those of the prototype to satisfy the morphological scaling factor.

4.2 Fluid Injection and Production Systems

4.2.1 Fluid Injection

Heavy oil was injected into the model by operating the positive displacement Milroyal pump at very slow flow rates. The brine was injected into the porous medium by using the constant rate screw-type piston pump. The flow rate on the pumps could be changed for different experiments depending on the experimental parameters.

At the initial stages of this research, carbon dioxide gas was injected by the screw-type piston pump at 5.5 MPa. This system depended on carbon dioxide behaving as a liquid at high pressures to determine accurately the volume injected. A new injection system was later developed to inject carbon dioxide as gas at low pressures.

4.2.2 Fluid Production

The effluent was collected in a graduated glass cylinder at atmospheric pressure. Oil and water were collected at the bottom of the cylinder while the gas was collected at the top. This gas was then connected to a simple measuring system where it displaced a certain volume of water equal to the total volume of oil, water and gas produced, in upright glass burettes. As a result, it was possible to determine to a high degree of accuracy, the volume of gas produced.

4.2.3 Gas Injection

At low pressures, carbon dioxide gas was injected using the Matheson gas metering system, which regulated and measured the gas entering the model. The necessary driving pressure was provided by the tank pressure. The Matheson Dyna-Blender monitored the mass flow rate of carbon dioxide. The value of the cumulative volume of gas injected was obtained from the digital readout on the Matheson Totalizer.

4.2.4 Gas Production

The produced gas was initially measured using the Dry Test Meter (DTM). This gas production apparatus (DTM) at the downstream flow end was found to be quite inaccurate when it was used to measure very small quantities of carbon dioxide gas. In most experiments, the volume of gas produced was very small, and this resulted in inaccurate measurement of the produced gas. As a result of this inadequacy of the DTM, an improved system was assembled. In this assembly, gases produced displaced a certain volume of water filled in upright glass burettes. The gases produced, at each stage of the experiment, were thus measured to a greater degree of accuracy. (Section 4.2.2)

In addition, the gas flow meter upstream was unable to measure accurately the carbon dioxide gas from the tank because it was difficult to maintain accurately a pressure differential of 5 psi across it. Therefore, a gas compressor was installed immediately after the gas flow controller which raised the pressure of the gas to the required value for the experiment.

4.3 Data Acquisition System

The production pressure was controlled by the back pressure regulator (BPR) connected to the downstream side of the model. Heise gauges connected to the pressure transducers were used to monitor the injection and production pressures.

4.4 Experimental Apparatus and Procedure

Different laboratory experiments were conducted in both one- and two-dimensional models. It should be pointed out that the "one-" and "two-" dimensional designations are only for convenience, because in the real sense, flow is three-dimensional in any physical model. Efforts were made to minimize the effects of the third dimension.

The linear model was relatively small in size compared to the two-dimensional model, making it possible to carry out experiments in a shorter time span and providing a useful means of screening different categories of runs in the two-dimensional model. It was designed to simulate a direct line drive flooding pattern. The two-dimensional model, on the other hand, was designed to simulate various flood patterns like the five-spot pattern, nine-spot pattern and line drive. In the present research, it was used to simulate a quarter of a five-spot pattern.

A model experiment followed the following sequence. During the packing process, the physical model was vibrated using an air vibrator. The linear model was dry packed, while the two-dimensional model was wet packed. The wet pack method gave a tighter pack and was more consistent.

The dry pack procedure was carried out by placing the model in a vertical position and strapping the vibrator to the side of the model. The porous medium (Ottawa sand, mesh size #70-140) settled down by the action of the vibrator over a period of eight to ten hours. The flange at the top was then closed, and a vacuum pump was connected to one end to evacuate air from the model. The model was again vibrated for eight to ten hours and at the end of this period, a vacuum existed in the model. A tube from a calibrated cylinder containing water was connected to one end and the water was displaced by air at atmospheric pressure. The amount of water displaced was equal to the pore volume of the model. The porosity was then calculated by dividing the pore volume over the bulk volume of the model.

The wet pack procedure was applied for the two-dimensional model. Initially, the model was placed in an upright position and some water was added to the core and the vibrator turned on. An aluminium casing was temporarily fixed to the top of the model, for the casing was used as an extension above the model, to maintain a head of water above the sand level. Sand was added until it reached the head of the model and was then vibrated for a duration of up to eight to ten hours. Afterwards, the casing and the vibrator were removed and the top flange of the model was fixed. The pore volume was determined by flowing brine through the model from the bottom to the top. The brine displaced the in-place water and when a 100% brine solution was produced, the process was terminated. The refractive index of the produced liquid was measured to show a gradual change from water to brine solution. The values were first plotted as the refractive index verses the percent salinity of the produced solution. From these values, the produced liquid was plotted against the percent brine. The curve extended from 0% brine to 100% brine against the produced liquid. The area under the curve was divided into two equal halves, and the mid point of the curve gave the pore volume of the model. From this, the value of the porosity was determined. Figures 4.3 and 4.4 illustrate the method used to calculate the pore volume of the two-dimensional model.

The procedure to determine the permeability of the core was the same for both physical models. The permeability of the core was calculated by flowing water through the core in a horizontal position, at a specific flow rate and pressure differential. A known volume of water was collected at a given time and pressure differential, and the permeability was calculated using the following equation

$$k = \frac{q.\mu.L}{A.\Delta P}$$

where: k = absolute permeability (L^2)
q = flow rate (L^3t^{-1})
μ = water viscosity ($ML^{-1}t^{-1}$)
L = length of the core (L) and
ΔP = pressure differential across the core ($ML^{-1}t^{-2}$).

Thereafter, the model was flooded with the oil of interest to irreducible water saturation. Then, the experimental flood scheme was initiated by injecting slugs of carbon dioxide and brine. Typically, ten slugs of gas and brine were followed by the waterflood phase till a WOR of 20:1 was reached. Then the injection port was closed and the back pressure

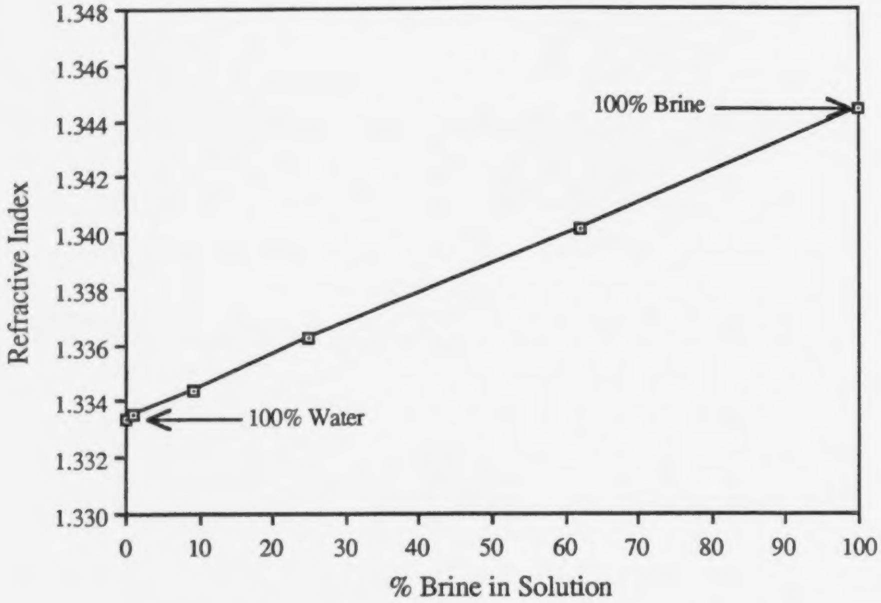


Figure 4.3: Calculation of the Amount of Brine in Solution for the Two-Dimensional Model.

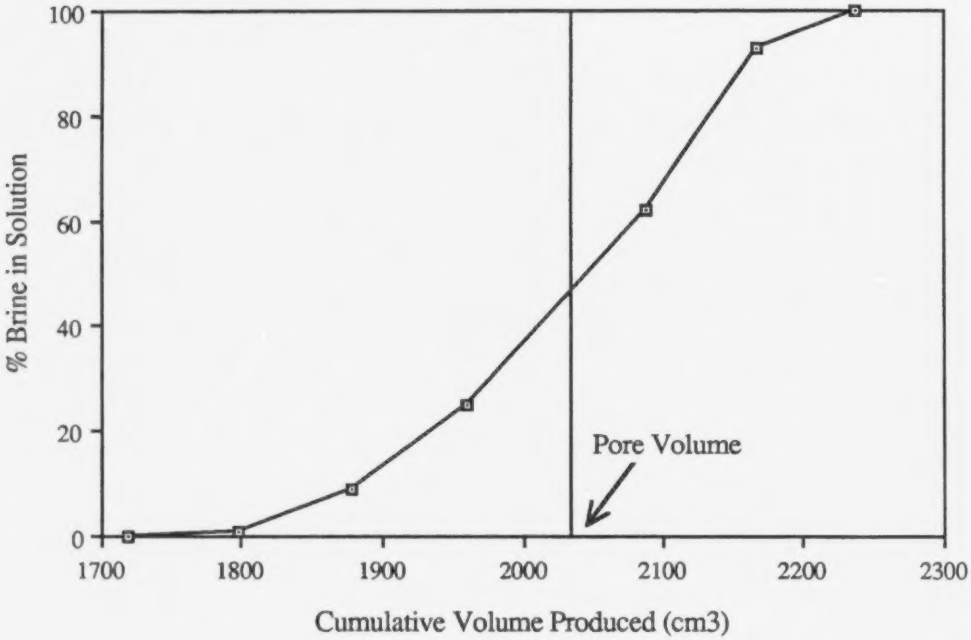


Figure 4.4: Pore Volume Determination for theTwo-Dimensional Model.

regulator at the production end was released to atmospheric pressure, thereby releasing the gas present in the model allowing the blowdown recovery phase to take place.

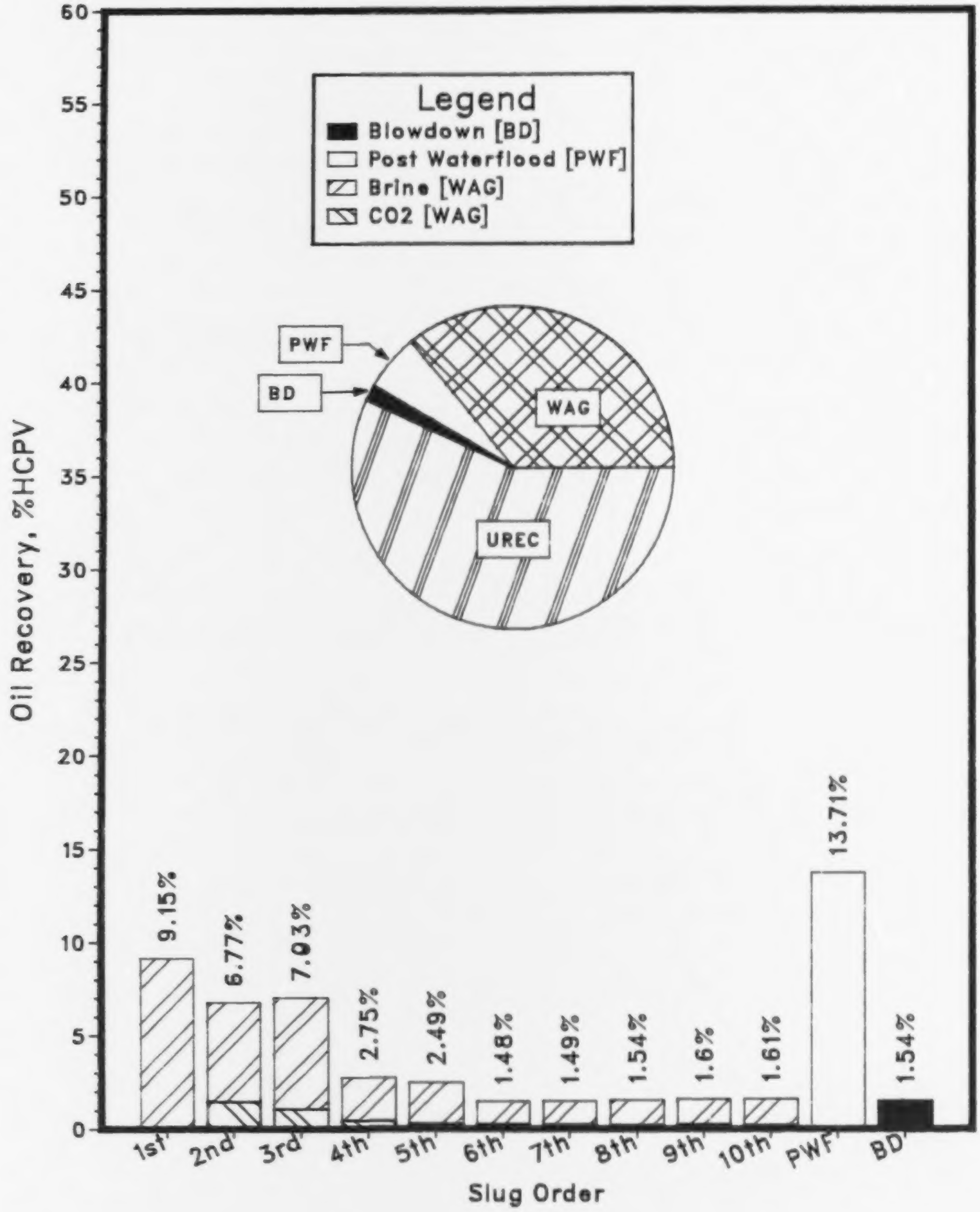
During the course of an experiment, fluid injection was carried out by a positive displacement Milroyal pump to saturate the porous medium with brine and oil. A constant rate, syringe-type positive displacement pump was used to inject brine into the porous medium during the experiments. Carbon dioxide was released from the tank and passed through a gas flow controller, which regulated and measured the volume of gas used. This gas was then compressed to the required experimental pressure and pumped directly into the model. Consequently, it was possible to inject a predetermined volume of gas at any pressure.

Previous researchers[4,6,7] performed experiments at 5.5 MPa to simulate the initial pressure of the reservoir. The present group of experiments was conducted at 2.5 and 1.0 MPa to simulate a depleted reservoir. In the present research live oil samples were also used for selected runs to examine the effect of dissolved gases on the process efficiency. A suitable apparatus was designed to saturate a given dead oil sample with methane, at the desired pressure.

The experimental data were recorded and summarized in Tables in Appendix C specifying the operating pressure, volume of carbon dioxide gas and water injected, volume of oil, water and gas produced, percent of oil recovered, water-oil ratio, gas-oil ratio and oil produced fluid injected ratio. From the tabulated data, graphs were generated to illustrate the variations as the experiment proceeded through the various phases and flow mechanisms.

Bar graphs were used to illustrate the individual recoveries derived from the ten gas and water slugs followed by the waterflood and blowdown recoveries. A pie chart was used to illustrate the recovery attained from each phase of the experiment as percentages of the total recovery. A material balance graph (volumetric) illustrated the oil, water, and gas produced during an experiment. A few examples of the model diagrams are presented using the data from Run LC 33. Figure 4.5 illustrates the oil recovery distribution of Run LC 33.

An overall material balance check was made by adding all the components and was then compared to an ideal material balance curve. The deviation of the calculated curve from the ideal indicated the error.



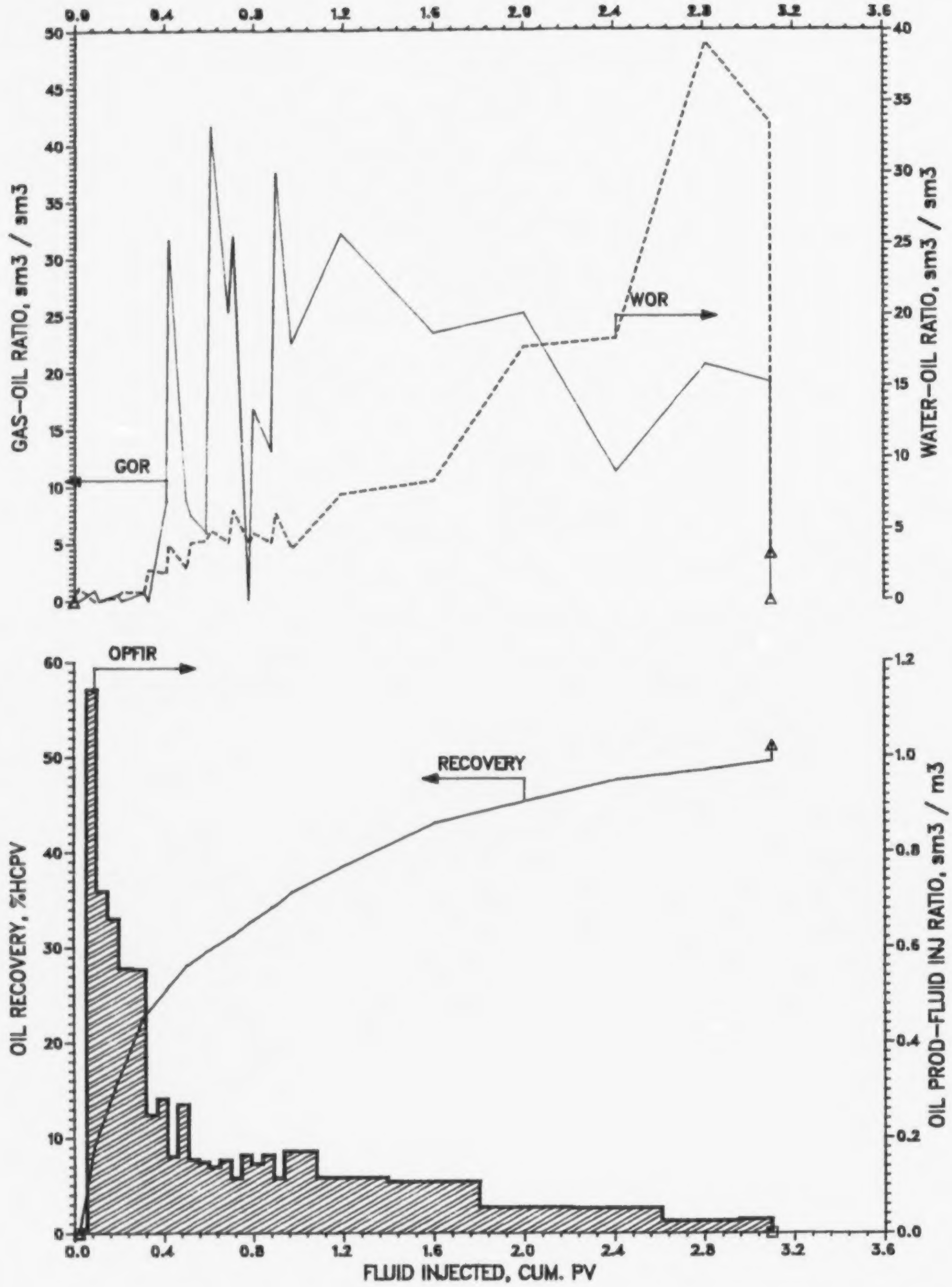
NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1230.0 mPa.s
ϕ = 37.44 %, k = 13.080 darcies, S_o = 94.94 %, S_{wc} = 5.06 %

[0.20 HCPV CO2 @ 2.5 MPa (0.22 g-mol) 4:1 WAG, 10-Slugs]

Figure 4.5: Oil Recovery Distribution of Run LC 33.

The production history curves indicate the gas-oil ratio (GOR), the cumulative oil recovery, and the oil-produced fluid injected ratio, all plotted against the total volume of fluid injected. The points of the curve indicate the number of times the data was recorded. The gas-oil ratio curve usually had large variations indicating the relative flow of gas and oil. A large value at the beginning indicated the gas breakthrough. The gas-oil ratio was a function of pressure and could be controlled by the oil production rates. When gas began to flow more rapidly than oil, it resulted in a larger gas-oil ratio. The gas-oil ratio declined as the gas was depleted and the reservoir pressure reached zero. Figure 4.6 is an illustration of the production history of Run LC 33 showing the various parameters mentioned.

The water-oil ratio (WOR) curve was usually very low at the initial stages of the experiment, as only low volumes of water were produced, and progressively increased as more water was produced at the later phases of the experiment. The process mobilization efficiency was illustrated by the instantaneous oil-produced fluid injected ratio curve.[11]



NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1230.0 mPa.s
ϕ = 37.44 %, k = 13.080 darcies, S_o = 94.94 %, S_{wc} = 5.06 %

[0.20 HCPV CO2 @ 2.5 MPa (0.22 g-mol) 4:1 WAG, 10-Slugs]

Figure 4.6: Production History of Run LC 33.

5. DISCUSSION OF RESULTS

5.1 General Description

A number of runs was conducted in both linear and two-dimensional models at *low pressures* (1.0 to 2.5 MPa) to determine the effect of the carbon dioxide *slug size, flow rate* and *operating pressure* on the recovery performance of an immiscible (subcritical) carbon dioxide displacement. Table 5.1 summarizes the experiments conducted in the two-dimensional model, Table 5.2 summarizes the linear model experiments, and Table 5.3 gives the results for the live oil experiments. Detailed tabulated results for each run are presented in Appendix C, the oil recovery distribution in Appendix D, the production histories of all the runs in graphical form in Appendix E, and the volumetric material balance plots in Appendix F.

Model parameters like ϕ, k_{abs}, S_o, and S_{wc} were fairly consistent in all the runs. As the viscosity of the original oil from the Lloydminster Aberfeldy reservoir was high, it was mixed with a conventional light oil (FAXAM-100) to reduce its viscosity to the scaled value. The average porosity was approximately 37.0% for the linear model, and 40.5% for the two-dimensional model. The average absolute permeability to the reservoir water was 12.3 darcies. Initial oil saturation for each run was in the range of 85 to 90% pore volume, the remaining 10 to 15% pore volume being the irreducible water saturation.

The flow chart illustrated in Fig. 5.1 provides an outline of the different experiments conducted in the linear and the two-dimensional models. The experiments can be divided into two groups consisting of those conducted in the linear and two-dimensional models, respectively. The linear model experiments are divided into three groups. The first group consists of the experiments conducted with different parameters at 2.5 MPa, the second group of the live oil experiments at 1.0 MPa, and the third group of the dead oil experiments conducted at 1.0 MPa. The two-dimensional model experiments also are divided into three groups. The first group consists of the experiments conducted at 2.5 MPa, with different slug sizes and flow rates. The second group comprises experiments conducted at a low pressure, viz. 1.0 MPa, with three different slug sizes, and the third group consists of the runs conducted at a flow velocity half of that used in the previous set of experiments. Live oil experiments refer to those using laboratory prepared oil samples containing gas-in-solution, while dead oil samples refer to oil samples with no solution gas.

TABLE 5.1

COMPARISON OF RESULTS — TWO-DIMENSIONAL MODEL EXPERIMENTS.

Experiment No.	GTD1	GTD2	GTD3	GTD4	GTD5	GTD6	GTD7	GTD8	GTD9	GTD10
Type of Experiment	S. WAG	S. WAG	S. WAG	S. WAG	S. WAG	S. WAG	S. WAG	S. WAG	S. WAG	S. WAG
Type of Oil	Dead Oil	Dead Oil	Dead Oil	Dead Oil	Dead Oil	Dead Oil	Dead Oil	Dead Oil	Dead Oil	Dead Oil
Average Pressure (MPa)	2.5	2.5	2.5	2.5	1.0	1.0	1.0	1.0	1.0	1.0
CO2 Volume Injected (% HCPV)	2	20	10	30	10	20	30	10	20	30
Brine Flow Velocity (m/d)	1.29	1.55	2.6	2.6	2.6	2.6	2.6	1.29	1.29	1.29
WAG Ratio	40: 1	4:1	4:1	4:1	4:1	4:1	4:1	4:1	4:1	4:1
Number of Slugs Injected	10	10	10	10	10	10	10	10	10	10
gm - moles	0.42	0.45	0.445	0.682	0.078	0.151	0.219	0.071	0.154	0.229
Pore Volume (cm3)	2024	2025	2004	2025	2104	2050	1850	1850	1850	1925
Porosity (%)	41.6	41.6	41.1	41.6	43.2	42.1	38.0	38.0	38.0	39.5
Initial Oil Saturation (%)	85.9	91.3	91.3	93.2	85.6	84.9	91.1	88.9	95.8	91.7
HCPV (cm3)	1740.2	1849.3	1795.6	1887.1	1801.3	1741.3	1684.4	1643.8	1772.3	1764.4
Oil Viscosity (mPa.s)	1230	1115	1115	1130	1135	1175	1279	1046	1046	1046
Absolute Permeability (darcies)	13.6	13.9	18.7	13.6	11.5	12.4	11.9	12.2	11.8	12.1
Connate Water Saturation (%)	14.1	8.7	8.7	6.8	14.4	15.1	8.9	11.1	4.2	8.3
Total Oil Produced (ml)	571.1	626.3	762.7	765.7	645.2	893.5	734.5	605.3	822.0	778.7
WAG Recovery (%)	28. 05	29.1	27.0	33.3	25.8	35.7	39.5	22.0	33.6	34.9
Waterflood Recovery (%)	4.4	4.5	13.4	0.1	9.0	13.2	1.0	13.8	9.5	6.6
Blowdown Recovery (%)	0.41	0.25	2.11	7.16	1.00	2.41	3.03	0.98	3.28	2.60
Total Recovery (%)	32.8	33.9	42.5	40.6	35.8	51.3	43.6	36.8	46.4	44.1
Unrecovered (%)	67.2	66.1	57.5	59.4	64.2	48.7	56.4	63.2	53.6	55.9
CO2 Requirement (sm3/sm3)	19.7	16.3	7.3	22.5	4.5	4.0	7.2	3.0	4.1	6.1
CO2 Retention (% inj)	95.4	35.5	99.1	75.3	99.9	54.0	4.0	15.0	38.0	12.3

Symbols and Abbreviations

S. WAG	Secondary WAG Process
HCPV	Hydrocarbon Pore Volume

TABLE 5.2

COMPARISON OF RESULTS - LINEAR MODEL EXPERIMENTS.

Experiment Number	LC 30	LC 31	LC 32	LC 33	LC 34	LC 35	LC 36
Type of Experiment	S. WAG	S. WAG	S. WAG	S. WAG	Waterflood	T. WAG	S. WAG
Type of Oil	Dead oil	Dead oil	Dead oil	Dead oil	Dead oil	Dead oil	Dead oil
Average Pressure (MPa)	2.5	2.5	2.5	2.5	2.5	2.5	2.5
CO2 Volume Injected (% HCPV)	89	20	40	20	0	20	5
Brine Flow Velocity (m/d)	0.98	0.98	0.98	0.98	0.98	0.98	0.98
WAG Ratio	4:1	4:1	4:1	4:1	α	4:1	4:1
Number of Slugs Injected	10	10	10	10	10	10	10
gm - moles	1.13	0.22	0.53	0.22	0.24	0.24	0.064
Pore Volume (cm3)	1170	1130	1170	1164	1134	1134	1155
Porosity (%)	37.6	36.4	37.6	37.4	36.5	36.5	37.1
Initial Oil Saturation (%)	90.2	79.4	93.7	94.9	92.5	54.2	91.8
HCPV (cm3)	1056	896	1096	1105	1049	614	1061
Oil Viscosity (mPa.s)	1055	1055	1055	1230	882	882	1130
Absolute Permeability (darcies)	11.4	11.0	14.1	13.1	9.9	9.9	11.2
Connate Water Saturation (%)	9.8	20.6	6.3	5.1	7.5	45.8	8.2
Total Oil Produced (ml)	530.0	510.9	450.7	565.2	435.0	212.4	492.6
WAG Recovery (%)	47.2	39.4	35.2	35.9	0.0	2.9** / 5.00*	21.1
Waterflood Recovery (%)	0.0	17.1	4.5	13.7	41.5	0.0** / 0.0*	22.7
Blowdown Recovery (%)	3.03	0.56	1.43	1.54	0.00	17.3** / 29.6*	2.60
Total Recovery (%)	50.2	57.0	41.1	51.1	41.5	61.7** / 34.6*	46.4
Unrecovered (%)	49.8	43.0	58.9	48.9	58.5	38.3** / 65.4*	53.6
CO2 Requirement (sm3/sm3)	47.6	9.5	27.7	11.1	0.0	5.5	3.3
CO2 Retention (% inj)	16.8	14.3	25.0	12.4	0.0	36.9	99.4

Symbols and Abbreviations

HCPV	Hydrocarbon Pore Volume
RHCPV	Residual Hydrocarbon Pore Volume
α	Denotes a WAG Ratio Corresponding to a Waterflood.
**	Denotes the Recovery of the Original Oil after the Initial Waterflood using the Tertiary Mode (HCPV)
*	Denotes the Residual Oil Recovery after the Initial Waterflood (RHCPV).
S.WAG	Secondary WAG Process
T.WAG	Tertiary WAG Process

TABLE 5.3

LINEAR MODEL : LIVE - OIL EXPERIMENTS.

Experiment No.	LC 37	LC 38	LC 39	LC 40	LC 41	LC 42	LC 43	LC 44
Type of Experiment	S. WAG	S. WAG	S. WAG	S. WAG	S. WAG	S. WAG	Waterflood	T. WAG
Type of Oil	Live-oil	Live-oil	Live-oil	Live-oil	Live-oil	Dead oil	Live-oil	Live-oil
Average Pressure (MPa)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CO2 Volume Injected (% HCPV)	20	40	10	20	20	20	0	20 RHCPV
Brine Flow Velocity (m/d)	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
WAG Ratio	4:1	4:1	4:1	4:1	4:1	4:1	α	4:1
Number of Slugs Injected	10	10	10	10	10	10	0	10
gm - moles	0.076	0.198	0.047	0.091	0.091	0.089	0	0.039
Pore Volume (cm3)	1142	1239	1142	1110	1210	1135	1092	1092
Porosity (%)	36.7	39.9	36.7	35.7	38.9	36.1	35.1	35.1
Initial Oil Saturation (%)	88.7	90.5	95	94.1	92.3	90.2	92	41.1
HCPV (cm3)	880	1140	1085	1044	1117	1024	1005	449
Oil Viscosity (mPa.s)	784	784	784	784	784	1046	784	784
Absolute Permeability (darcies)	9.2	11.8	13.6	10.2	14.2	11.0	10.5	10.5
Connate Water Saturation (%)	11.3	9.5	5	5.9	7.7	9.8	8	58.9
Total Oil Produced (ml)	584.7	739.1	678.3	663.3	725.8	523.0	556.0	123.8
WAG Recovery (%)	43.40	51.78	32.96	39.97	39.69	35.01	0.00	2.4*/5.3
Waterflood Recovery (%)	14.41	4.81	26.69	16.95	18.75	14.36	55.3 IWF	3.7*/8.4
Blowdown Recovery (%)	8.63	8.24	2.86	6.61	6.54	1.70	0.00	6.2*/13.9
Total Recovery (%)	66.44	64.83	62.51	63.53	64.98	51.07	55.32	67.6*/27.6
Unrecovered (%)	33.56	35.17	37.49	36.47	35.02	48.93	44.70	32.4*/72.4
CO2 Requirement (sm3/sm3)	3.4	6.6	2.0	4.3	3.8	5.7	0.0	1.4
CO2 Retention (% inj)	***	***	***	***	***	9.69	0	***

Symbol and Abbreviations

HCPV	Hydrocarbon Pore Volume
RHCPV	Residual Hydrocarbon Pore Volume
α	Denotes a WAG Ratio Corresponding to a Waterflood.
***	Denotes the Value Which Was Not Calculated as the Value of Total Gas (CO2 + CH4) in the System is Unknown.
**	Denotes the Recovery of the Original Oil after the Initial Waterflood using the Tertiary Mode (HCPV).
*	Denotes the Residual Recovery after the Initial Waterflood (RHCPV).
S. WAG	Secondary WAG Process
T. WAG	Tertiary WAG Process

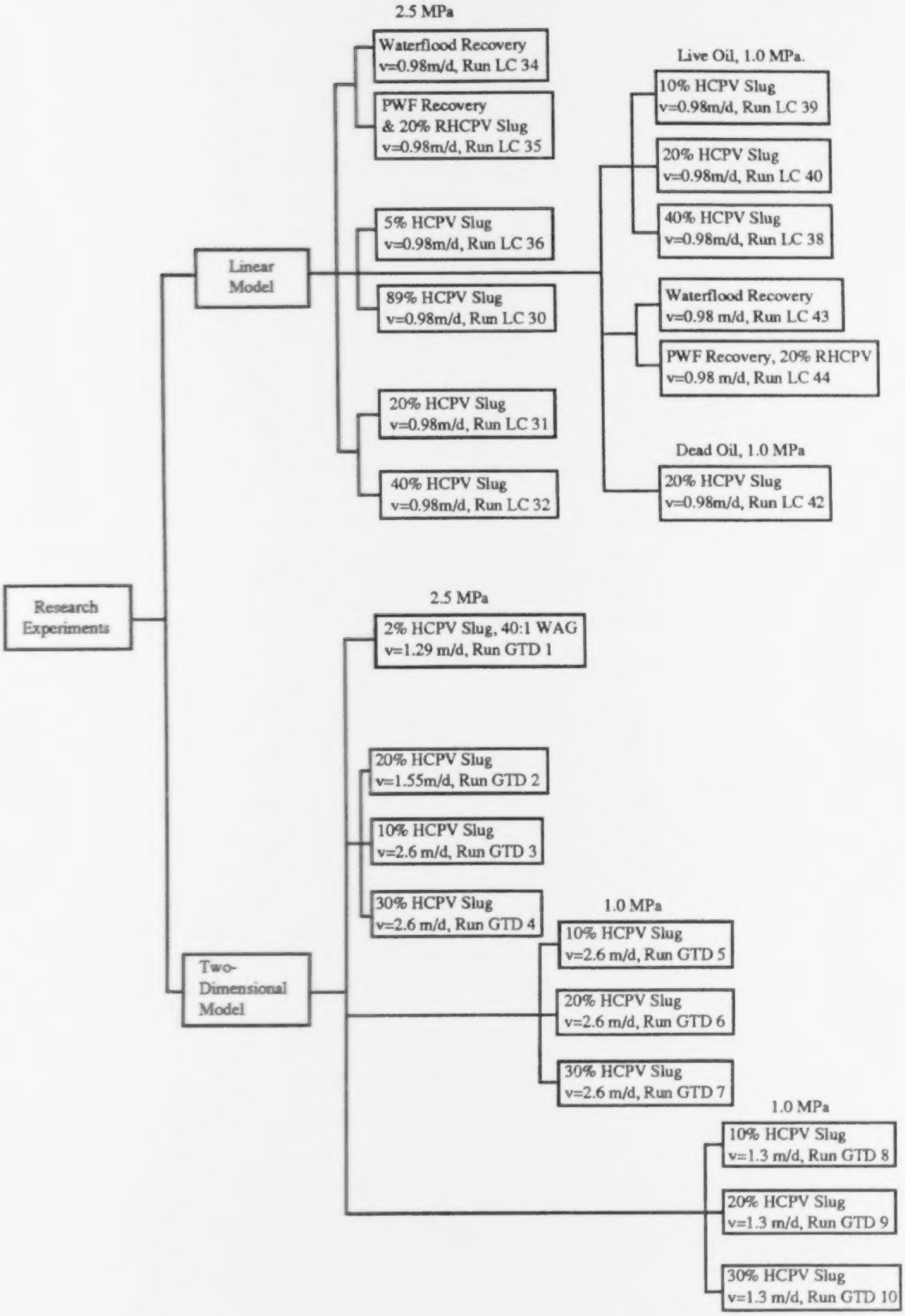

Research Experiments
Linear Model
2.5 MPa
Waterflood Recovery v=0.98m/d, Run LC 34
PWF Recovery & 20% RHCPV Slug v=0.98m/d, Run LC 35
5% HCPV Slug v=0.98m/d, Run LC 36
89% HCPV Slug v=0.98m/d, Run LC 30
20% HCPV Slug v=0.98m/d, Run LC 31
40% HCPV Slug v=0.98m/d, Run LC 32
Live Oil, 1.0 MPa.
10% HCPV Slug v=0.98m/d, Run LC 39
20% HCPV Slug v=0.98m/d, Run LC 40
40% HCPV Slug v=0.98m/d, Run LC 38
Waterflood Recovery v=0.98 m/d, Run LC 43
PWF Recovery, 20% RHCPV v=0.98 m/d, Run LC 44
Dead Oil, 1.0 MPa
20% HCPV Slug v=0.98m/d, Run LC 42
Two-Dimensional Model
2.5 MPa
2% HCPV Slug, 40:1 WAG v=1.29 m/d, Run GTD 1
20% HCPV Slug v=1.55m/d, Run GTD 2
10% HCPV Slug v=2.6 m/d, Run GTD 3
30% HCPV Slug v=2.6 m/d, Run GTD 4
1.0 MPa
10% HCPV Slug v=2.6 m/d, Run GTD 5
20% HCPV Slug v=2.6 m/d, Run GTD 6
30% HCPV Slug v=2.6 m/d, Run GTD 7
1.0 MPa
10% HCPV Slug v=1.3 m/d, Run GTD 8
20% HCPV Slug v=1.3 m/d, Run GTD 9
30% HCPV Slug v=1.3 m/d, Run GTD 10

Figure 5.1 : Flow Chart of the Experiments Conducted.

The experiments designated GTD were carried out in the two-dimensional model, and those designated LC were carried out in the linear model. In previous studies,[1,3,5,6] most of the runs conducted in the two-dimensional model were at high pressures (2.5 MPa and 5.5 MPa), and a few were at 1.0 MPa to compare the results. Several experiments were also conducted to check the repeatability of experimental results and it was found that for a 20% HCPV slug carbon dioxide experiment, the reproducibility was within ± 2%. For every run conducted, a carbon dioxide gas slug was first injected followed by a water slug; this was repeated for ten pairs of carbon dioxide and water slugs.

The parameters affecting the use of carbon dioxide are: the carbon dioxide requirement, carbon dioxide retention and the carbon dioxide utilization. Carbon dioxide requirement is defined as the ratio of the total volume of carbon dioxide injected (sm^3) to the total volume of oil produced (sm^3) and increases with the total carbon dioxide slug size. Carbon dioxide retention is defined as the percentage of carbon dioxide that is not produced during the experiment. Usually, the higher the retention, the higher is the overall recovery. Carbon dioxide utilization is defined as the amount of carbon dioxide injected divided by the incremental oil recovered. A low utilization factor indicates that the response to carbon dioxide injection is favourable.

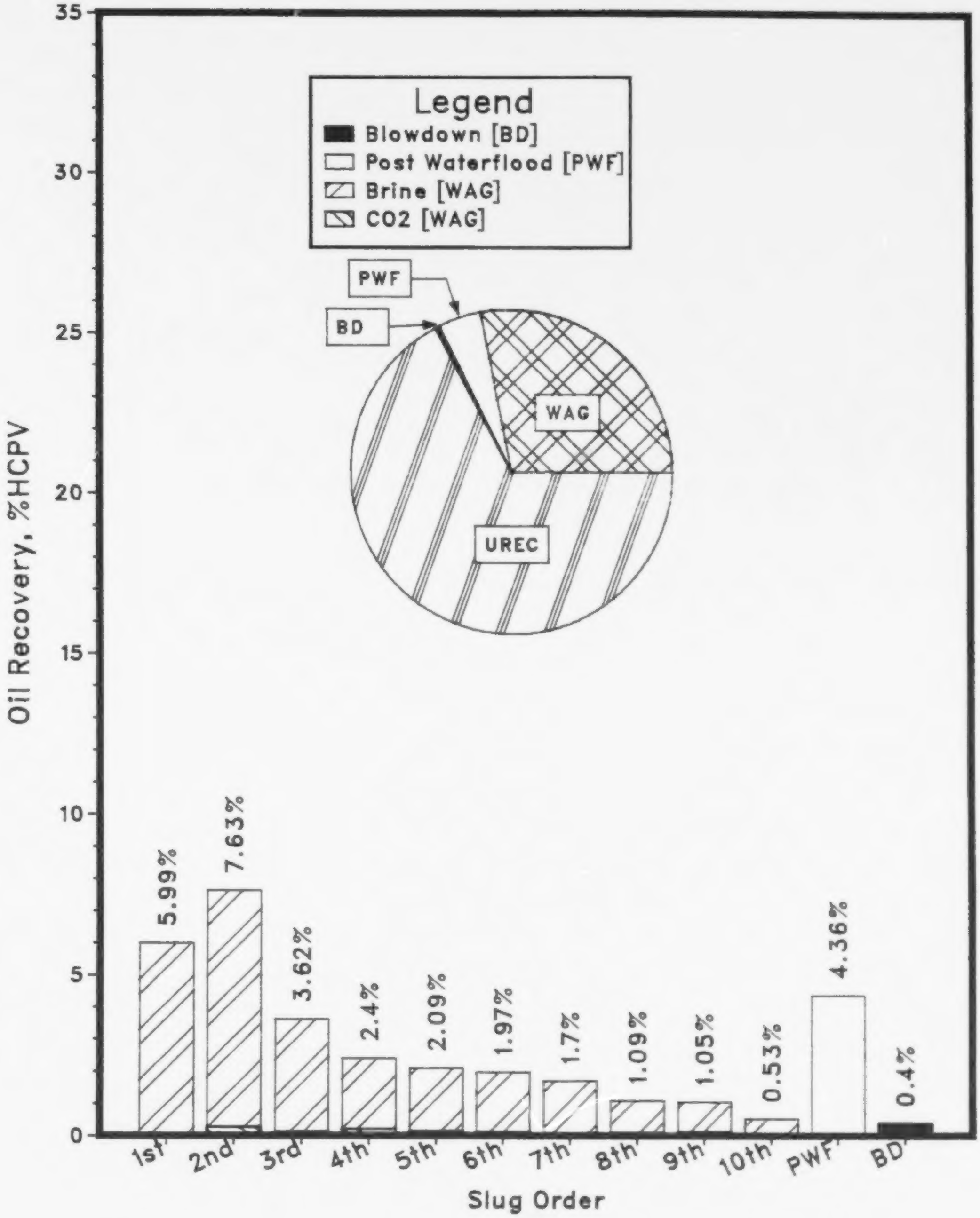
5.2 Presentation of the Experimental Results

5.2.1 Two-Dimensional Model Experiments

Presented below is a discussion of the experiments conducted in the two-dimensional model. The experiments used different slug sizes (10, 20 and 30% HCPV of carbon dioxide) at 2.5 and 1.0 MPa using different flow rates and their effect on recovery were studied.

5.2.1.1 Effect of a Small Carbon Dioxide Volume and a Large WAG Ratio (40:1)

In Run GTD 1, the experiment was conducted in the two-dimensional model at 2.5 MPa. The volume of carbon dioxide injected per slug was 0.2% HCPV, and the volume of brine injected per slug was calculated for a 40:1 WAG ratio. The oil recovered during the carbon dioxide WAG process was 28.1%, which was followed by the waterflood recovery of 4.4%. The blowdown phase recovery was 0.4% and the total oil recovered was 32.8%. Figure 5.2 shows the oil recovery distribution of Run GTD 1.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 1.290 m/d, μ_o = 1230.0 mPa.s
ϕ = 41.55 %, k = 13.080 darcies, S_o = 85.95 %, S_{wc} = 14.05 %

[0.02 HCPV CO2 @ 2.5 MPa (0.42 g–mol) 40:1 WAG, 10–Slugs, 2D Model]

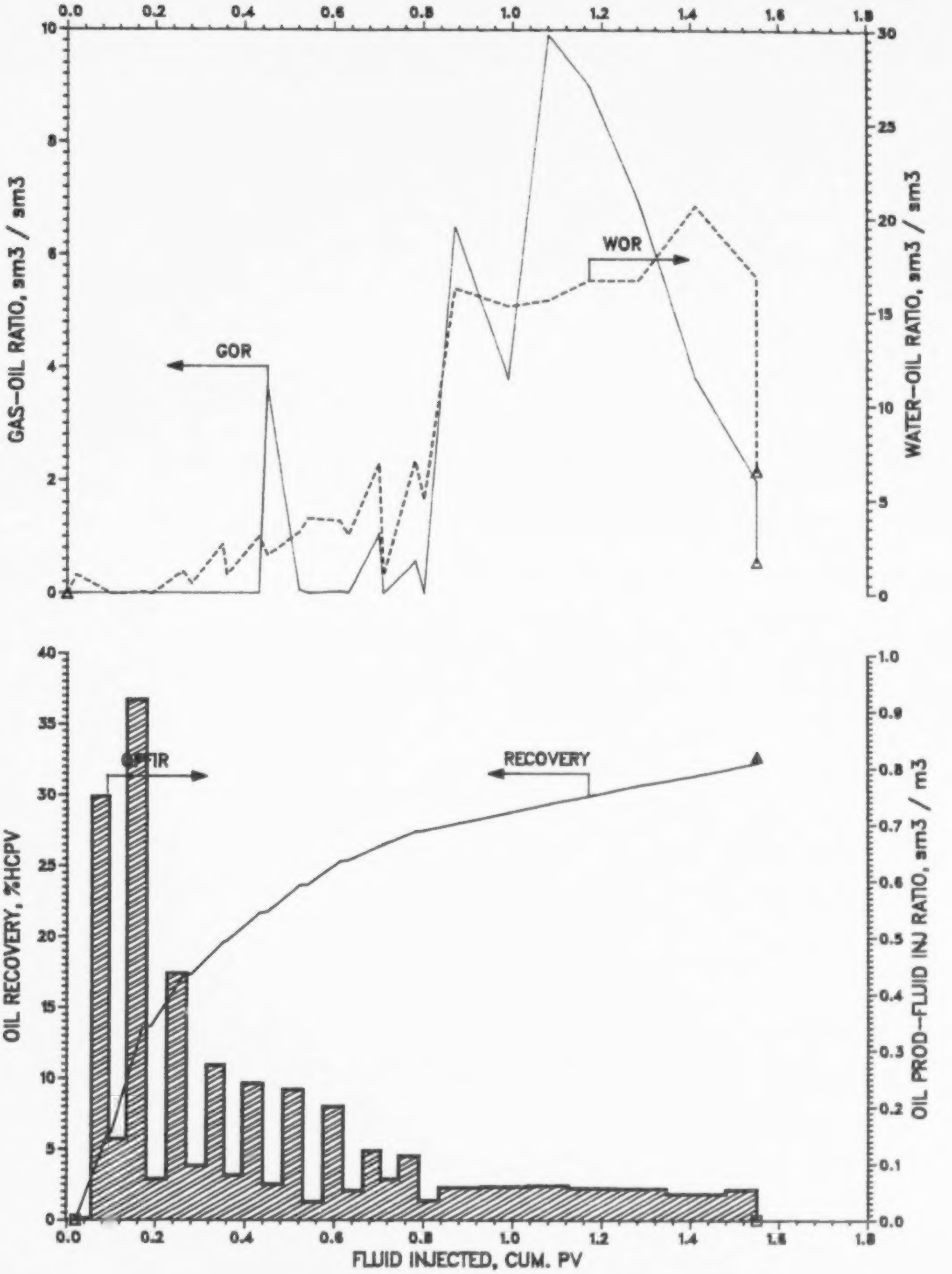
Figure 5.2: Oil Recovery Distribution of Run GTD 1.

As shown in the production history of Run GTD 1 in Fig. 5.3, the variations in the gas-oil ratio curve indicate that in the initial stages of the experiment, very little gas was produced. During the course of this run, relatively more gas was produced in the later portion of the experiment. It can be seen from the gas-oil ratio curve that when a small volume of carbon dioxide was injected, the volume of gas produced during the experiment was small also. The water-oil ratio curve also shows a similar trend but at a larger magnitude. Limited volumes of water were produced at the initial stage of the run, and then more water was produced as the experiment was continued. Therefore, the total oil volume recovered (32.8%) was relatively high for a small volume of carbon dioxide injected.

5.2.1.2 Effect of Flow Velocity

Three experiments, Run GTD 2 at 2.5 MPa and Runs GTD 6 and GTD 9 at 1.0 MPa, respectively, were conducted to evaluate the effect of pressure and flow velocity on the process efficiency. The carbon dioxide slug size in all runs was 20% HCPV (Fig. 5.4). For Run GTD 2, the oil recoveries at the WAG phase, post waterflood phase, and blowdown phase were 29.1%, 4.5%, and 0.2%, respectively, giving a total recovery of 33.9%. The WAG recovery for Run GTD 6 was 35.7%, the post waterflood recovery 13.2%, and the blowdown recovery 2.4%. Thus, the total recovery for this run was 51.3%. For Run GTD 9, the oil recovery was 33.6% for the WAG process, followed by 9.5% from the waterflood and 3.3% from the blowdown phase, with a total recovery of 46.4%. The flow velocity used in Run GTD 2 was 1.6 m/d, and 2.6 m/d for Run GTD 6. The flow velocity used in Run GTD 9 was one-half of that of Run GTD 6, i.e. 1.3 m/d.

The produced gas-oil ratio curve for Run GTD 6 shows small variations (Fig. 5.6), indicating efficient utilization of the gas. The gas-oil ratio curve for Run GTD 2 has very large values and fluctuations, indicating inefficient utilization of the carbon dioxide gas and early gas breakthrough (Fig. 5.5). Also, the flood life was the lowest of the three runs. When there was early gas breakthrough, the advantage of carbon dioxide mixing with oil was lost in the later stages of the experiment. The gas-oil ratio curves shown in Figs. 5.5-5.7 show that the produced gas-oil ratio was low when the slug size was small and when the injection rate was low. It was thus a function of how effectively the injected carbon dioxide was utilized. Thus, it was found that the oil recovery increased with an increase in flow velocity, as the higher flow velocities in the horizontal direction balances the gravitational forces.



NOTE: Average Run Conditions: Quarter of a 5-Spot, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 1.290 m/d, μ_o = 1230.0 mPa.s
ϕ = 41.55 %, k = 13.6 darcies, S_o = 85.95 %, S_{wc} = 14.05 %

[0.02 HCPV CO2 @ 2.5 MPa (0.42 g-mol) 40:1 WAG, 10-Slugs, 2D Model]

Figure 5.3: Production History of Run GTD 1.

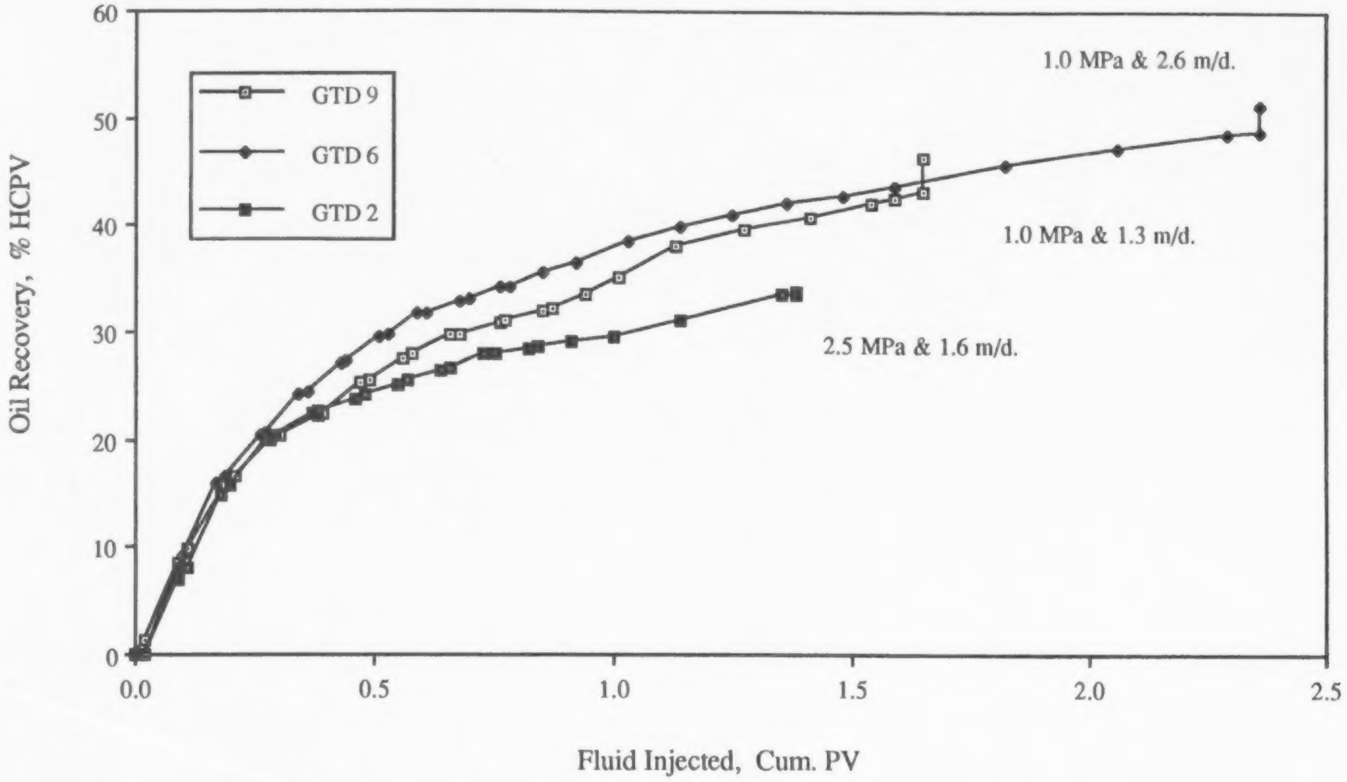


Figure 5.4: Production History of Two-Dimensional Model Experiments Injecting 20% HCPV CO2 at Different Operating Pressures and Flow Rates.

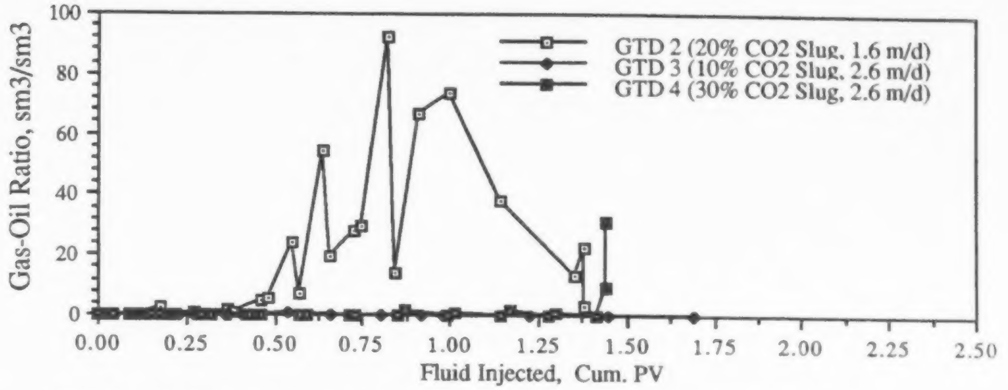


Figure 5.5: GOR Production History of the Two-Dimensional Experiments @ 2.5 MPa, 4:1 WAG and 10 Slugs.

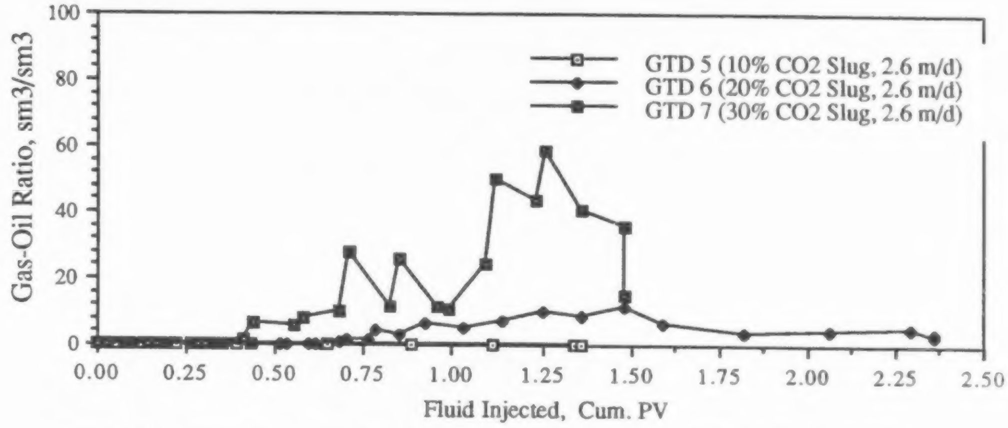


Figure 5.6: GOR Production History of Two-Dimensional Model Experiments @ 1.0 MPa, 4:1 WAG, and 10 Slugs.

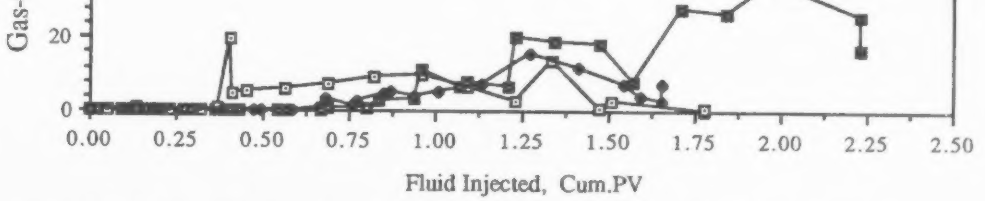


Figure 5.7: GOR Production History of Two-Dimensional Model Experiments @ 1.0 MPa, 4:1 WAG and 10 Slugs.

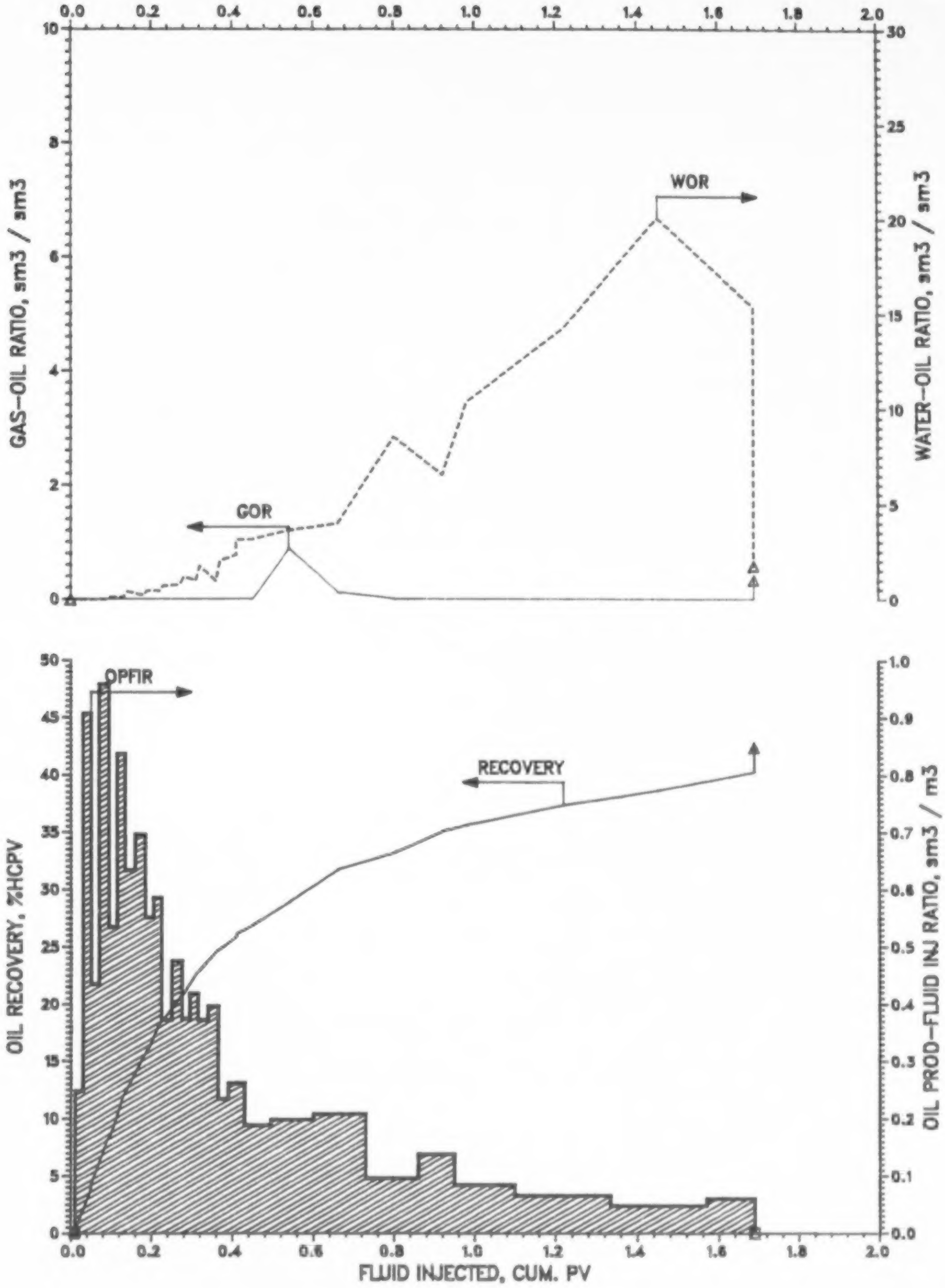
The detailed production history curves for Runs GTD 2, GTD 6 and GTD 9 are shown in Figs. D1 to D3, while the oil recovery distribution curves for these runs are shown in Figs. E1 to E3, which indicate that the first two slugs recover the most oil. The oil recovery was a stronger function of the carbon dioxide slug size, and increases with the injected flow velocity. Furthermore, it is more meaningful to consider the individual components of oil recovery (i.e. WAG recovery, waterflood recovery, and blowdown recovery).

5.2.1.3 Effect of Operating Pressure

In Runs GTD 3 and GTD 5, conducted at 2.5 MPa and 1.0 MPa, respectively, a 10% HCPV slug of carbon dioxide was injected. It was found that Run GTD 3 had a total recovery of 42.5%, made up of 27% by the WAG process and 13.4% by the post-waterflood. This was due to the fact that the water-oil ratio at the end of the WAG process was still significantly below the economic limit, i.e. 20:1, and so the waterflood was able to recover a considerable volume of oil. The blowdown phase recovered 2.11%. In Run GTD 5, the total recovery was 35.8%, made up of 25.8%, 9.0%, and 1.0% recovery from the WAG, waterflood, and blowdown phases, respectively. It was noted that the carbon dioxide retention for Run GTD 3 was 99.1%, and for Run GTD 5 about 99.9%. The production history curves for Runs GTD 3 and GTD 5 are shown in Figs. 5.8 and 5.9, while the oil recovery distribution curves for these two runs are shown in Figs. 5.10 and 5.11. As only a small volume of gas was injected, i.e. 10% HCPV, in these two runs, very little gas was produced as shown in the gas-oil ratio plots of Figs. 5.8 and 5.9. At higher pressures, carbon dioxide is more soluble in the oil, and this has an impact on oil recovery. The oil recovery, as illustrated in the order of slugs produced, shows that a relatively large volume of oil was produced in the waterflood and blowdown phases.

In Runs GTD 4 and GTD 7, conducted at 2.5 MPa and 1.0 MPa, respectively, a 30% HCPV slug of carbon dioxide was injected. While Run GTD 4 had a total recovery of 40.6%, 33.3% of the recovery was from the WAG process and 7.2% from the blowdown phase. For Run GTD 7, the total recovery was 43.6%, with 39.5% of the recovery from the WAG process alone, followed by 1.0% and 3.0% recovery from the waterflood and blowdown phases, respectively. Figures 5.12-5.14 summarize the results of oil recovery for the two-dimensional model runs.

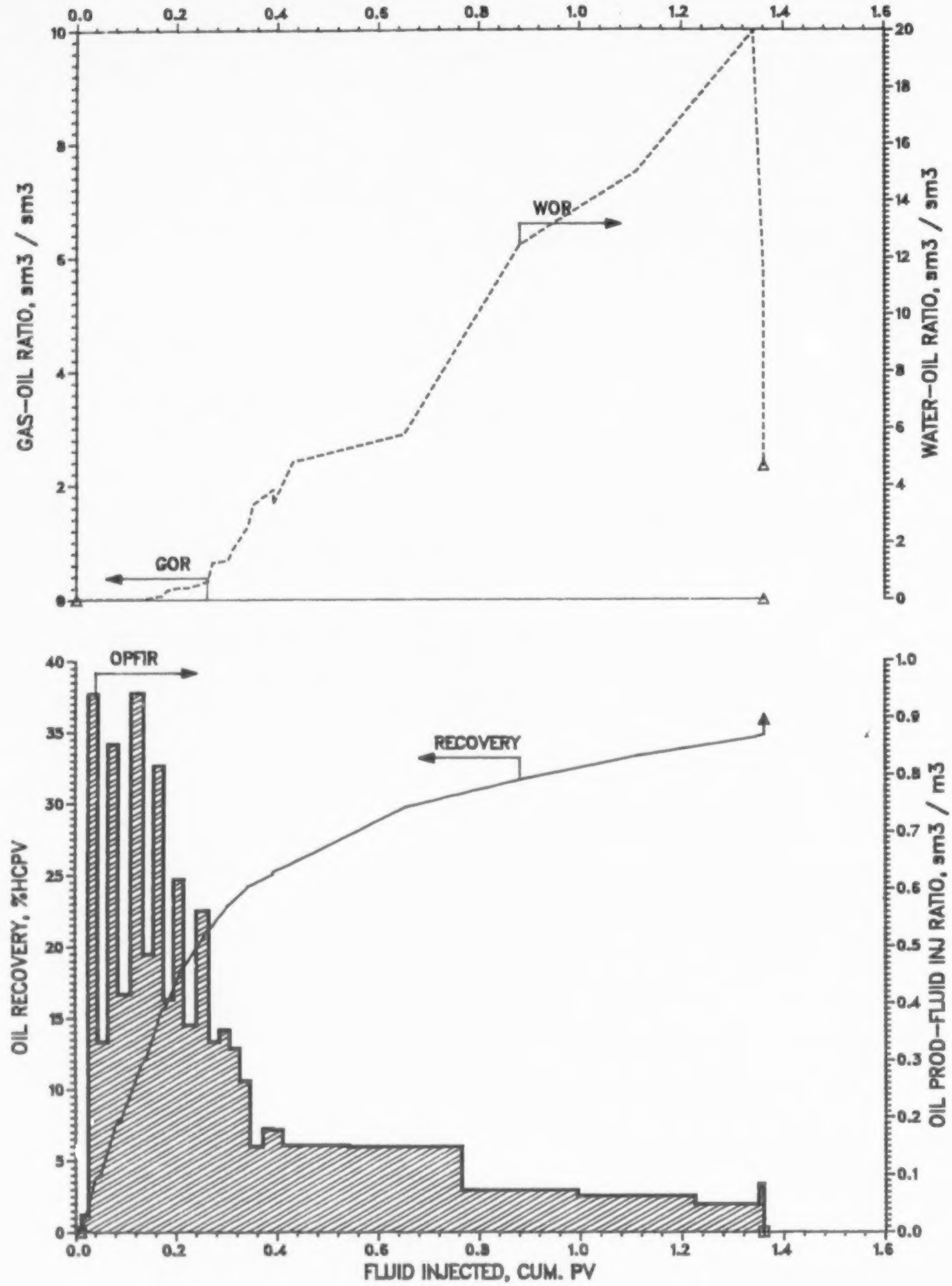
A comparison of Figs. 5.12 and 5.13 shows that the oil recovery for the WAG phase was higher at the higher flow velocity, for the 20% and 30% HCPV slugs. A comparison of



NOTE: Average Run Conditions: Quarter of a 5–Spot, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1115.0 mPa.s
ϕ = 41.1 %, k = 18.630 darcies, S_o = 91.30 %, S_{wc} = 8.7 %

[0.10 HCPV CO2 @ 2.5 MPa (0.445 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

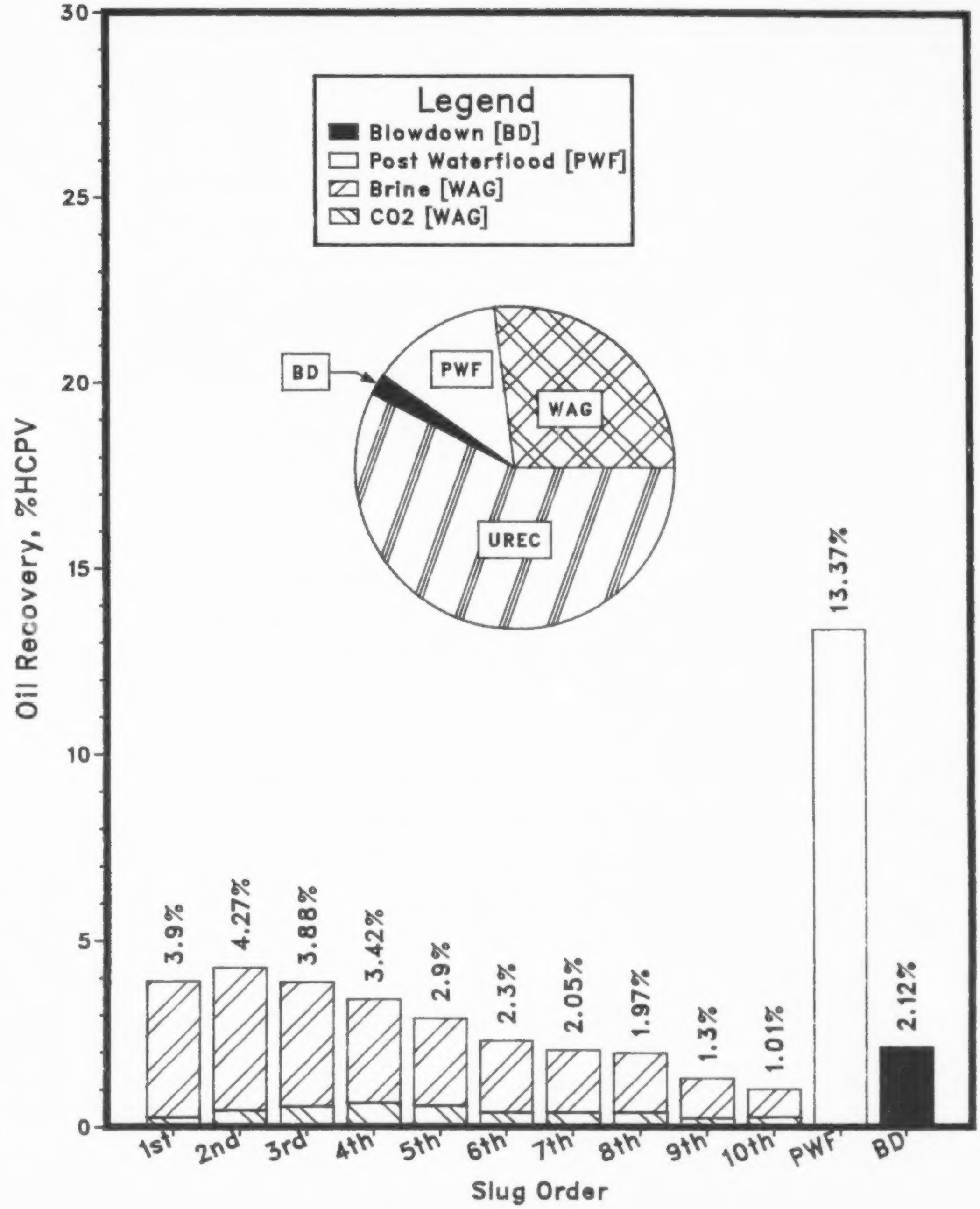
Figure 5.8: Production History of Run GTD 3.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1135.0 mPa.s
ϕ = 43.19 %, k = 11.520 darcies, S_o = 85.61 %, S_{wc} = 14.39 %

[0.10 HCPV CO2 @ 1.0 MPa (0.078 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

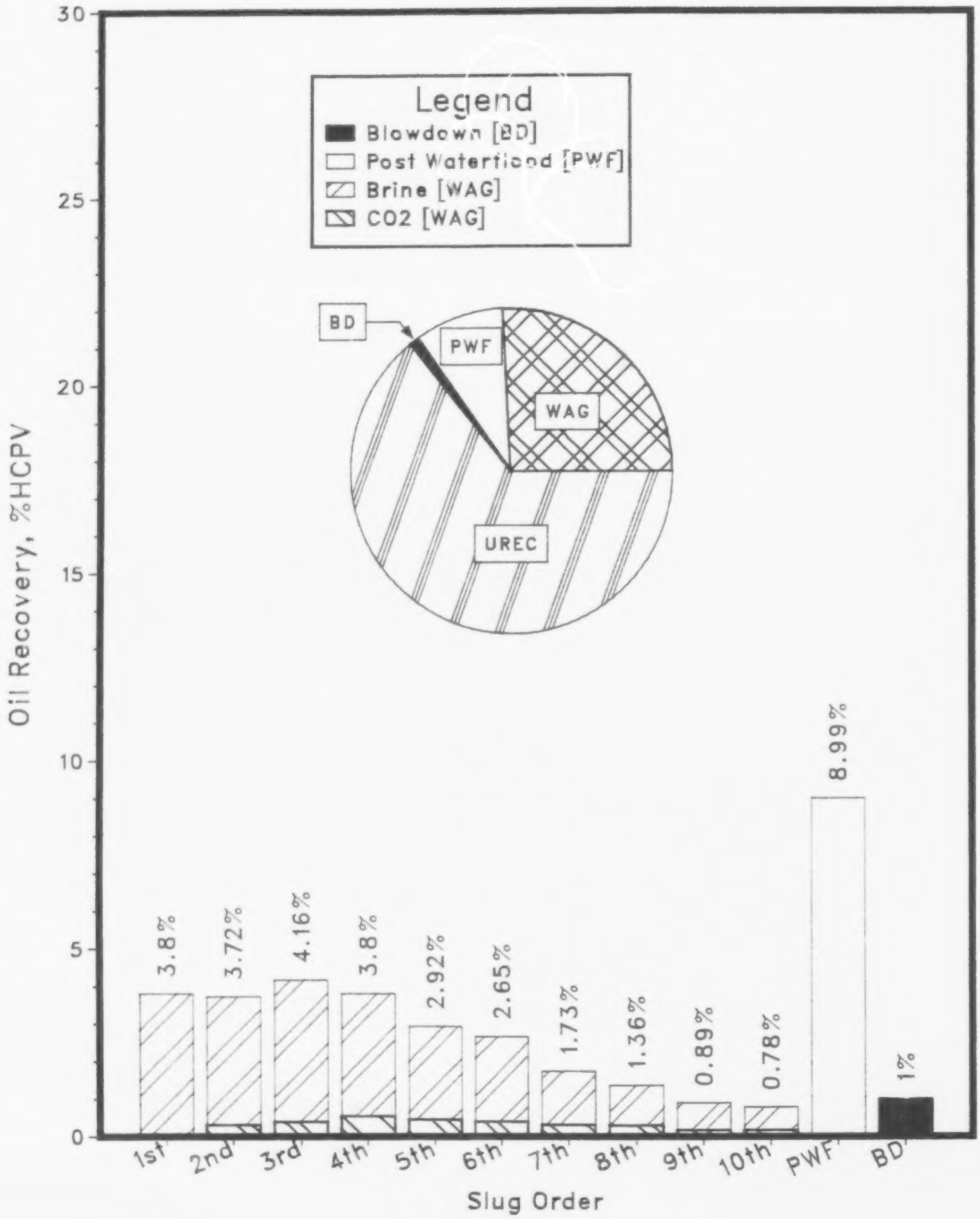
Figure 5.9: Production History of Run GTD 5.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1115.0 mPa.s
ϕ = 41.14 %, k = 18.630 darcies, S_o = 89.60 %, S_{wc} = 10.40 %

[0.10 HCPV CO2 @ 2.5 MPa (0.216 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

Figure 5.10: Oil Recovery Distribution of Run GTD 3.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1135.0 mPa.s
ϕ = 43.19 %, k = 11.520 darcies, S_o = 85.61 %, S_{wc} = 14.39 %

[0.10 HCPV CO2 @ 1.0 MPa (0.078 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

Figure 5.11: Oil Recovery Distribution of Run GTD 5.

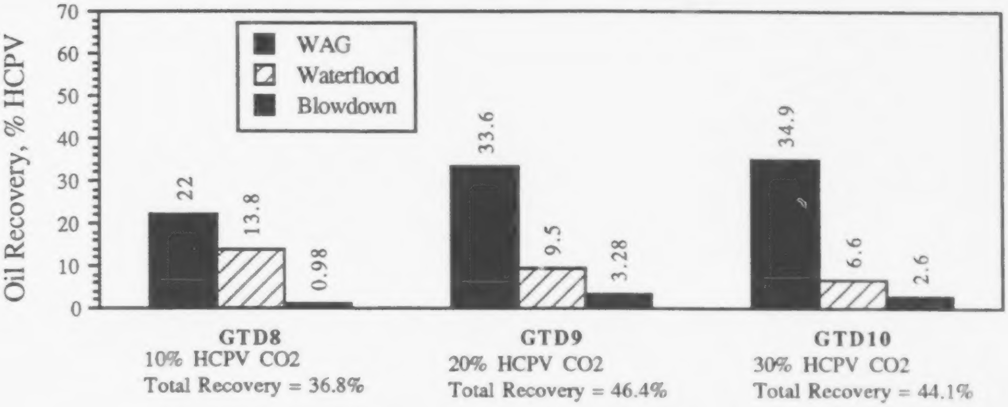


Figure 5.12: Two-Dimensional Model Experiments @ 1.0 MPa, 4:1 WAG, 10 Slugs and v=1.3m/d.

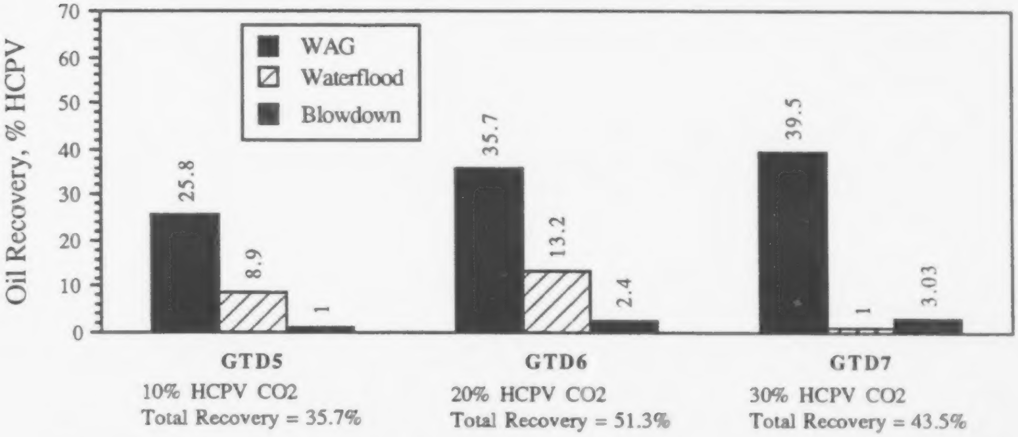


Figure 5.13: Two-Dimensional Model Experiments @ 1.0 MPa, 4:1 WAG, 10 Slugs and v=2.6m/d.

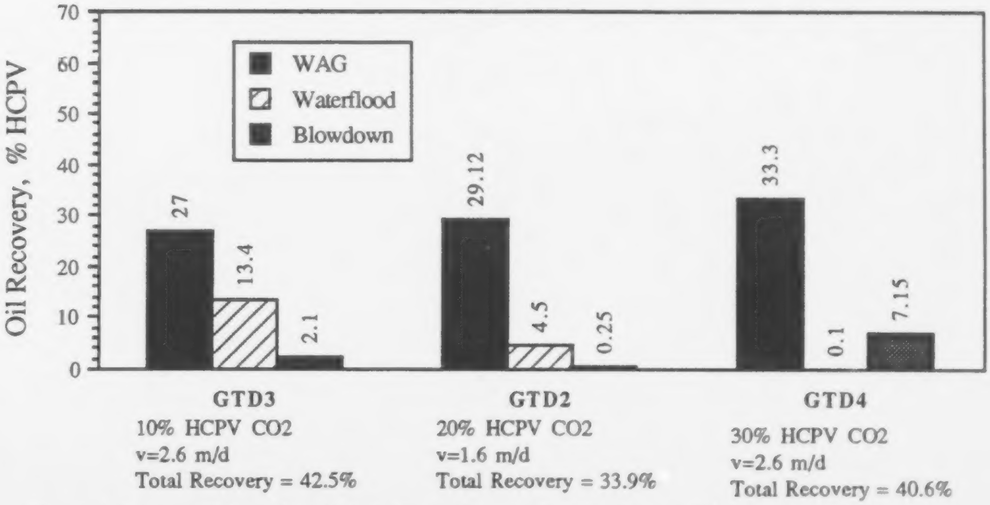


Figure 5.14: Two-Dimensional Model Experiments @ 2.5 MPa, 4:1 WAG and 10 Slugs.

Figs. 5.13 and 5.14 (same flow velocity) shows that the WAG recovery was higher at the lower pressure, but the blowdown recovery was higher at the higher pressure. It is believed that the *in situ* volume of carbon dioxide was larger at the lower pressure causing the displacement efficiency to be higher. Also at the higher pressure, more gas goes into solution, so the blowdown recovery is higher.

It is noted that the operating pressure had a significant effect on the carbon dioxide requirement and retention. At the higher pressure, both the carbon dioxide requirement and the retention increased due to increased solubility. Figures 5.15-5.17 show the carbon dioxide requirement and retention for the two-dimensional runs (Runs GTD 2 to GTD 10).

The production history curves for Runs GTD 4, GTD 7, GTD 8, and GTD 10 are shown in Figs. 5.18 to 5.21, and the oil recovery distribution for these runs are shown in Figs. 5.22 to 5.25. It was noticed that for Run GTD 4 (Fig. 5.18), the water breakthrough was delayed till 0.2 pore volume of fluid was injected. This was clearly reflected both in the oil recovery chart (Fig. 5.22) and in the OPFIR curve, where it is shown that the first two slugs recovered the most oil. For the case of Run GTD 7, the decrease in the oil produced to fluid injected ratio corresponded to the decrease in the gas-oil ratio as shown in Fig. 5.19. This is possibly due to the solution of carbon dioxide gas into the oil resulting in the delay in oil production.

5.2.1.4 Effect of Slug Size

All of the two-dimensional model experiments were conducted using three different slug sizes, i.e. 10%, 20%, and 30% HCPV of carbon dioxide. The previous researchers used different slug sizes with most of the experiments conducted using a slug size of 20% HCPV of carbon dioxide, as it had been found to give the optimum recovery.[3,5,6]

Figure 5.26 shows a comparison of the production histories for Runs GTD 5, GTD 6, and GTD 7, which utilized slug sizes of 10%, 20%, and 30% HCPV of carbon dioxide, respectively. This graph presents the values of the oil recovery versus the total cumulative fluid injected in pore volumes, and clearly shows that Run GTD 6, which utilized a 20% HCPV carbon dioxide slug, has the highest oil recovery of 51.3%. Figure 5.6 shows the gas-oil ratio versus the total cumulative fluid injected for the above mentioned runs.

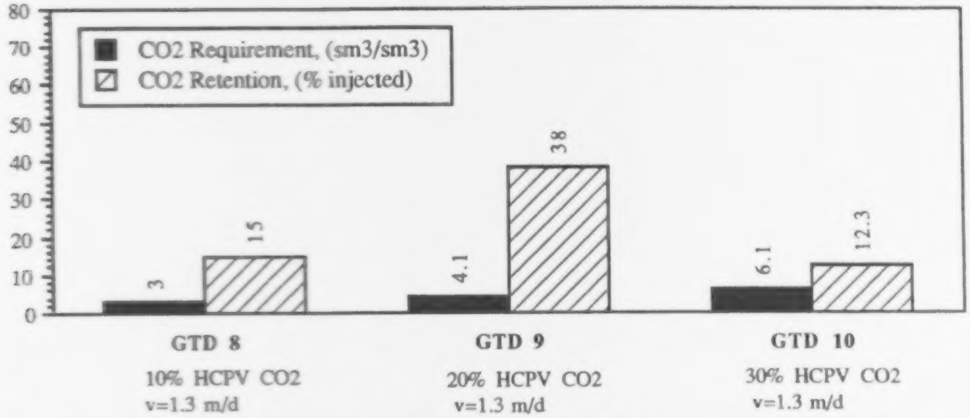


Figure 5.15: Two-Dimensional Model Experiments @ 1.0 MPa, 4:1 WAG, and 10 Slugs.

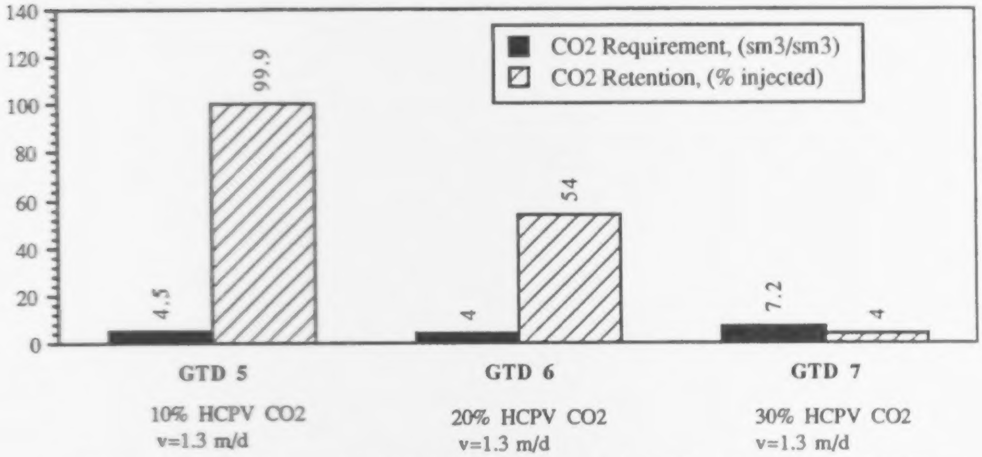


Figure 5.16: Two-Dimensional Model Experiments @ 1.0 MPa, 4:1 WAG, and 10 Slugs.

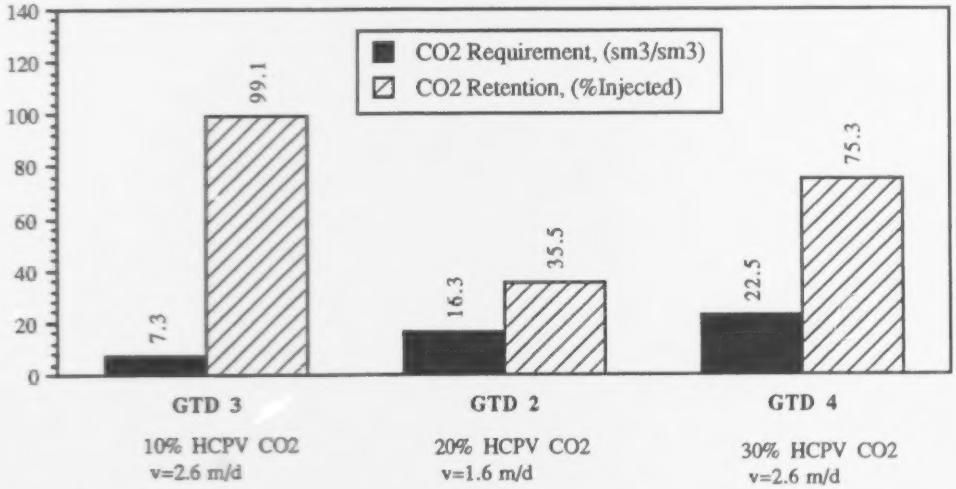
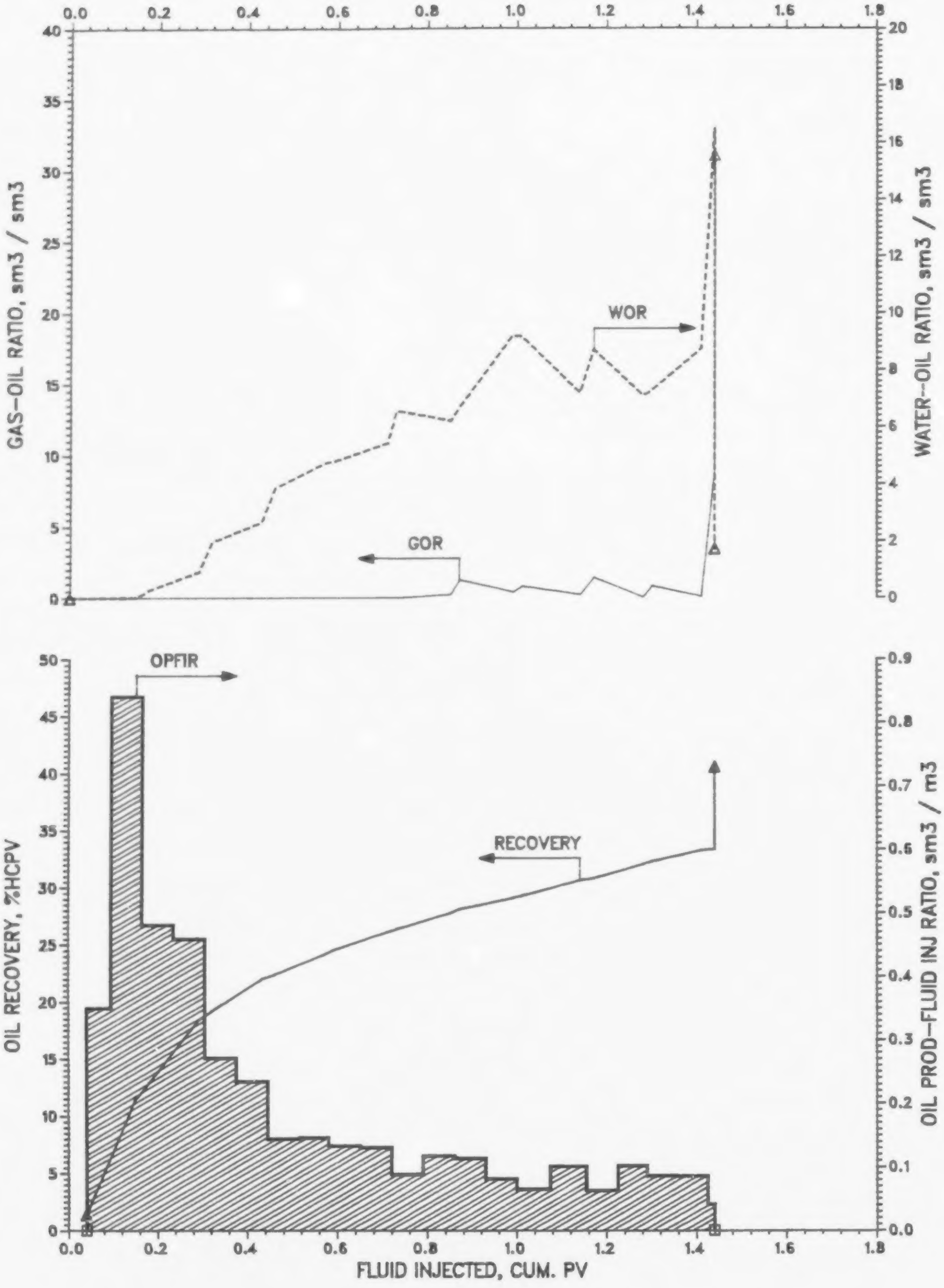


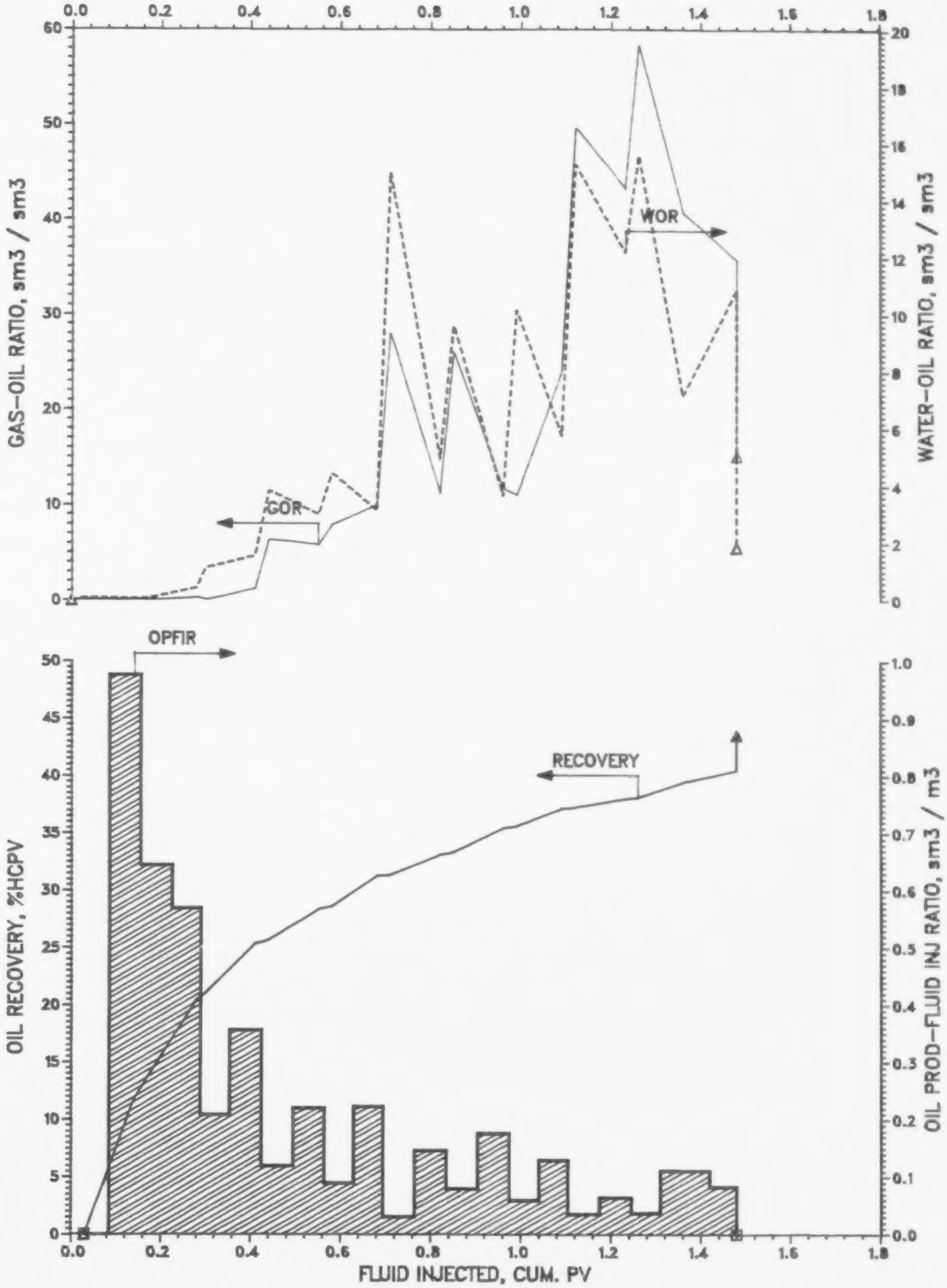
Figure 5.17: Two-Dimensional Model Experiments @ 2.5 MPa, 4:1 WAG, and 10 Slugs.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1135.0 mPa.s
ϕ = 41.57 %, k = 13.570 darcies, S_o = 93.19 %, S_{wc} = 6.81 %

[0.30 HCPV CO2 @ 2.5 MPa (0.682 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

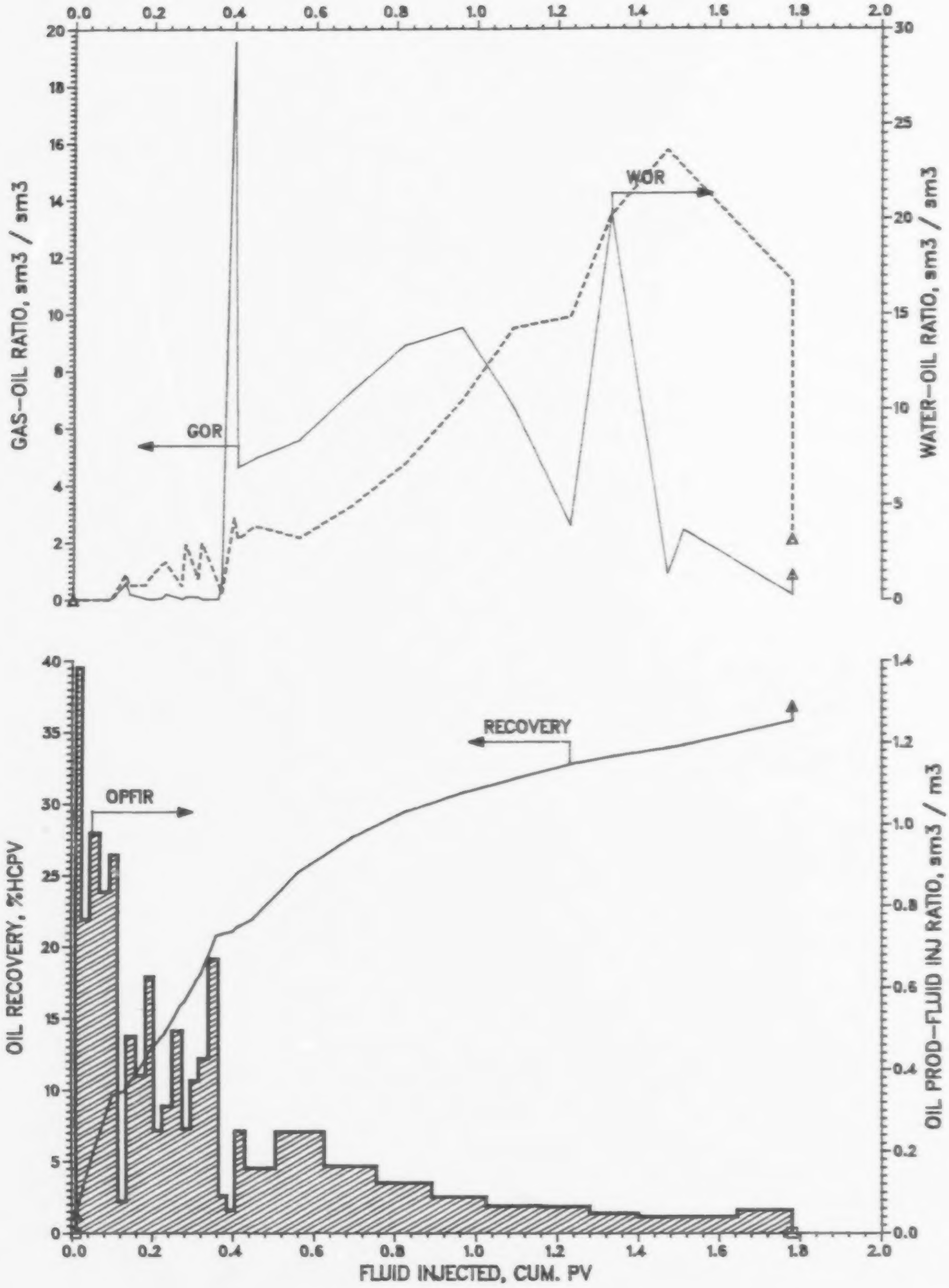
Figure 5.18: Production History of Run GTD 4.



NOTE: Average Run Conditions: Quarter of a 5-Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1279.0 mPa.s
ϕ = 37.97 %, k = 15.360 darcies, S_o = 91.05 %, S_{wc} = 8.95 %

[0.30 HCPV CO2 @ 1.0 MPa (0.219 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

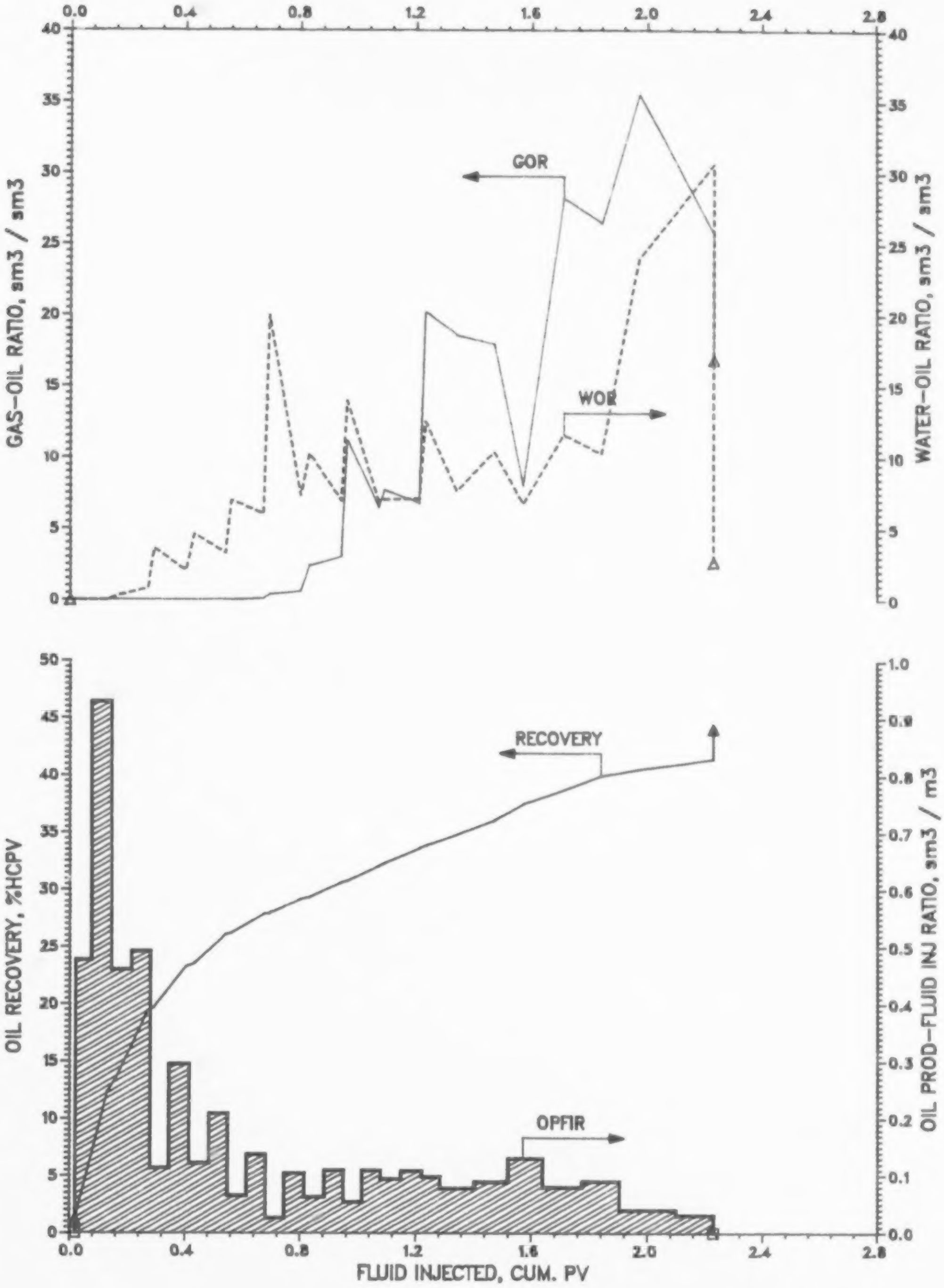
Figure 5.19: Production History of Run GTD 7.



NOTE: Average Run Conditions: Quarter of a 5-Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 1.290 m/d, μ_o = 1046.1 mPa.s
ϕ = 37.97 %, k = 15.360 darcies, S_o = 88.85 %, S_{wc} = 11.15 %

[0.10 HCPV CO2 @ 1.0 MPa (0.071 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

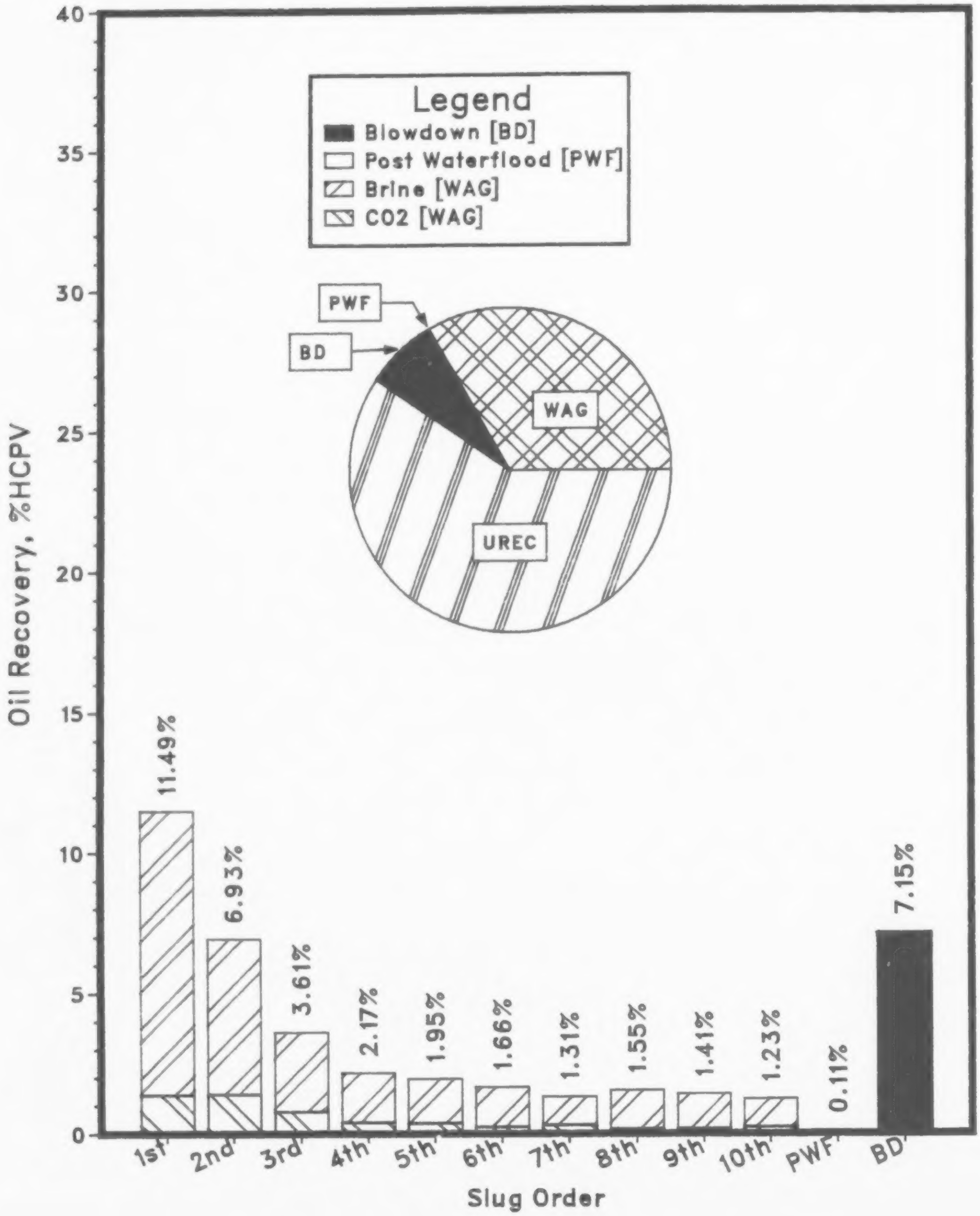
Figure 5.20: Production History of Run GTD 8.



NOTE: Average Run Conditions: Quarter of a 5-Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 1.290 m/d, μ_o = 1046.1 mPa.s
ϕ = 29.50 %, k = 12.100 darcies, S_o = 91.70 %, S_{wc} = 8.30 %

[0.30 HCPV CO2 @ 1.0 MPa (0.229 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

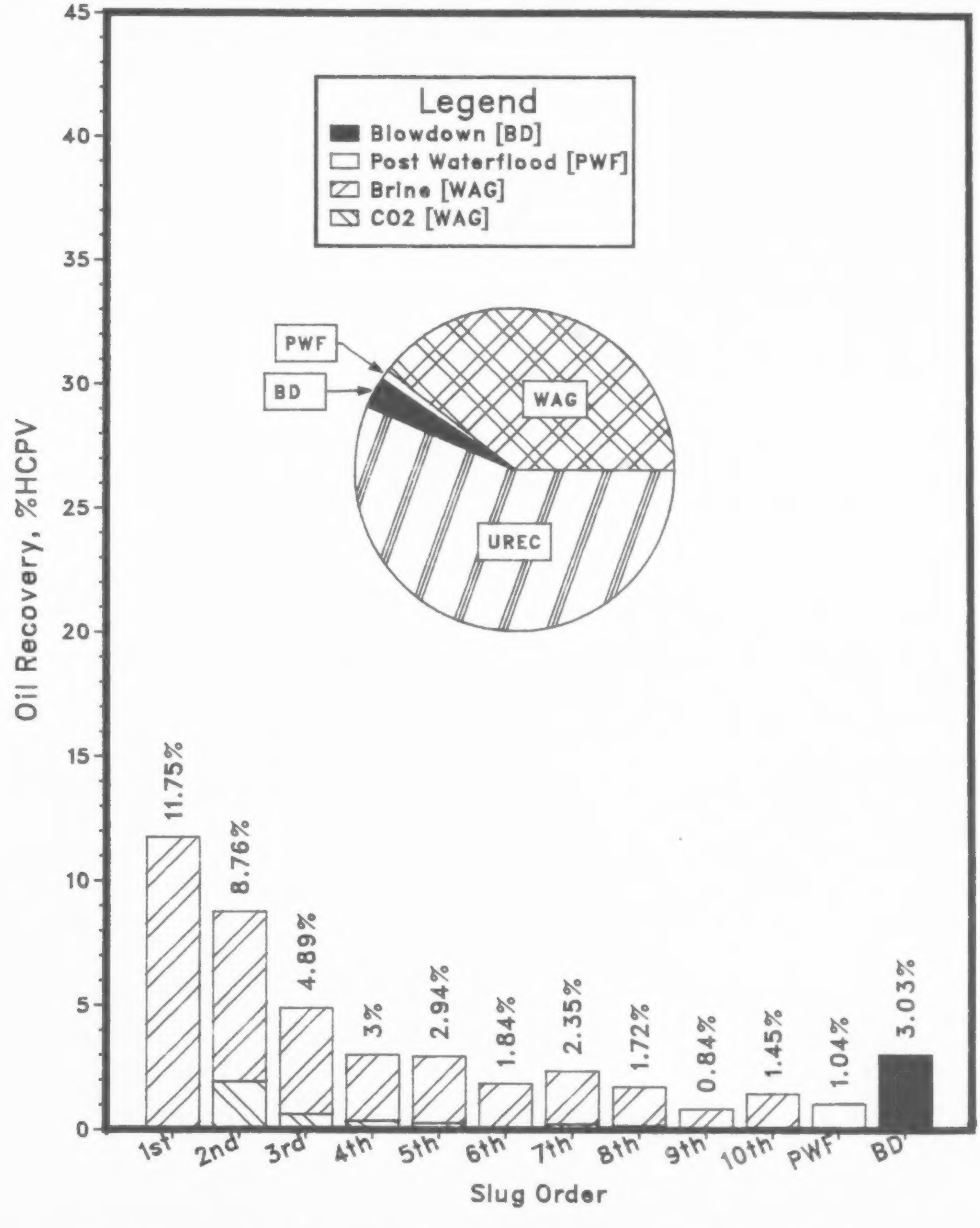
Figure 5.21: Production History of Run GTD 10.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1135.0 mPa.s
ϕ = 41.57 %, k = 13.570 darcies, S_o = 93.19 %, S_{wc} = 6.81 %

[0.30 HCPV CO2 @ 2.5 MPa (0.682 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

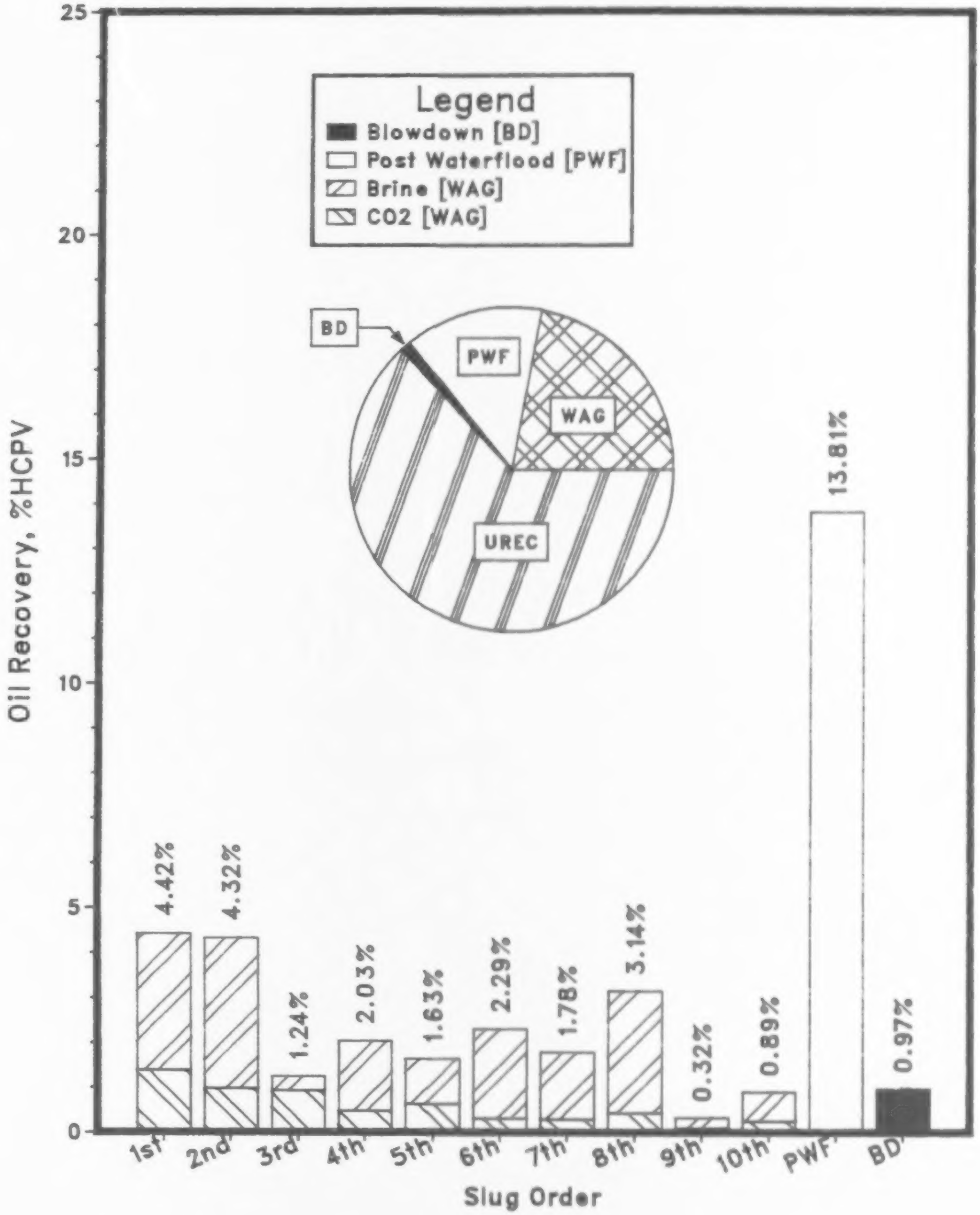
Figure 5.22: Oil Recovery Distribution of Run GTD 4.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1279.0 mPa.s
ϕ = 37.97 %, k = 15.360 darcies, S_o = 91.05 %, S_{wc} = 8.95 %

[0.30 HCPV CO2 @ 1.0 MPa (0.219 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

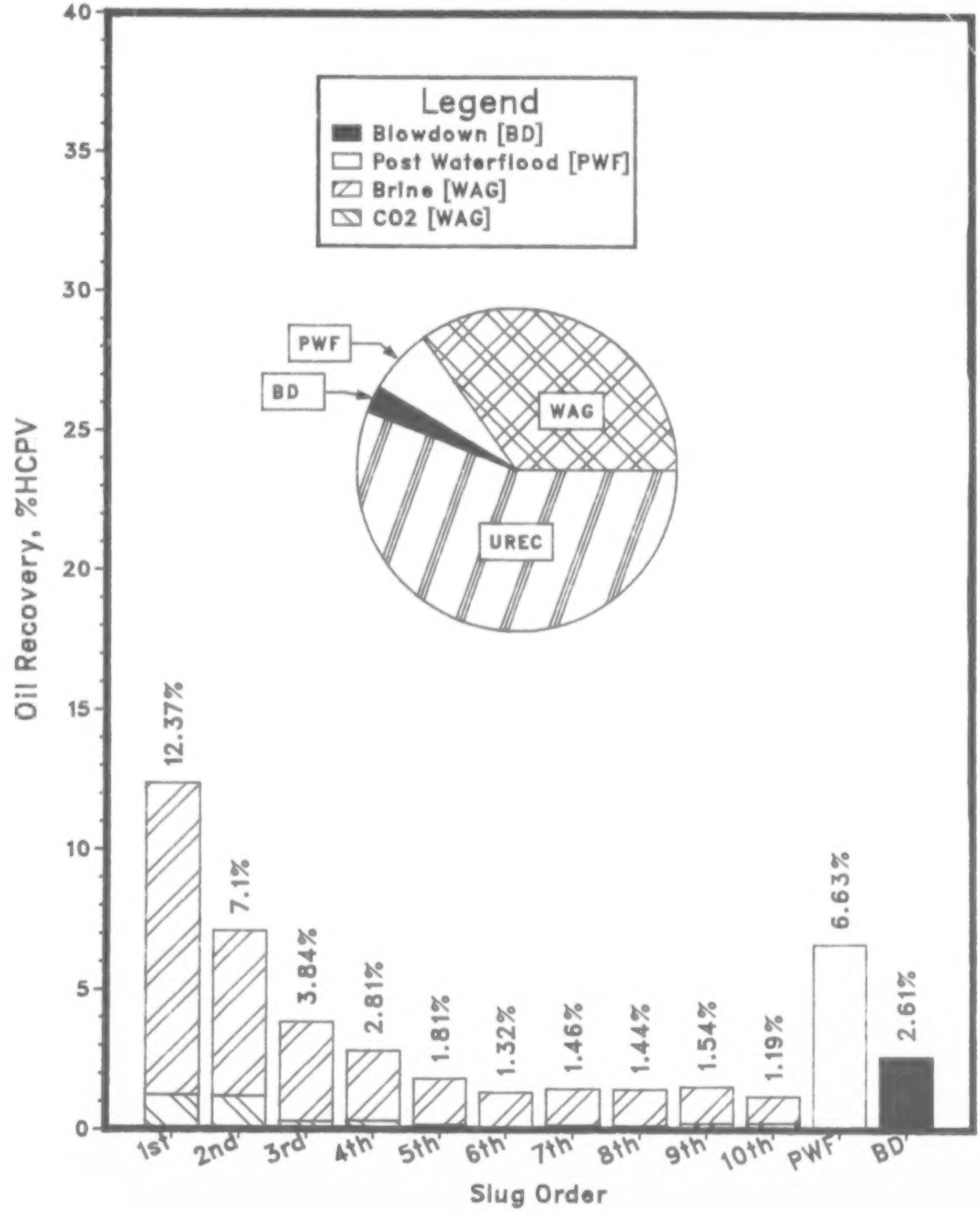
Figure 5.23: Oil Recovery Distribution of Run GTD 7.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 1.290 m/d, μ_o = 1046.1 mPa.s
ϕ = 37.97 %, k = 15.360 darcies, S_o = 88.85 %, S_{wc} = 11.15 %

[0.10 HCPV CO2 @ 1.0 MPa (0.071 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

Figure 5.24: Oil Recovery Distribution of Run GTD 8.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 1.290 m/d, μ_o = 1046.1 mPa.s
ϕ = 29.50 %, k = 12.100 darcies, S_o = 91.70 %, S_{wc} = 8.30 %

[0.30 HCPV CO2 @ 1.0 MPa (0.229 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

Figure 5.25: Oil Recovery Distribution of Run GTD 10.

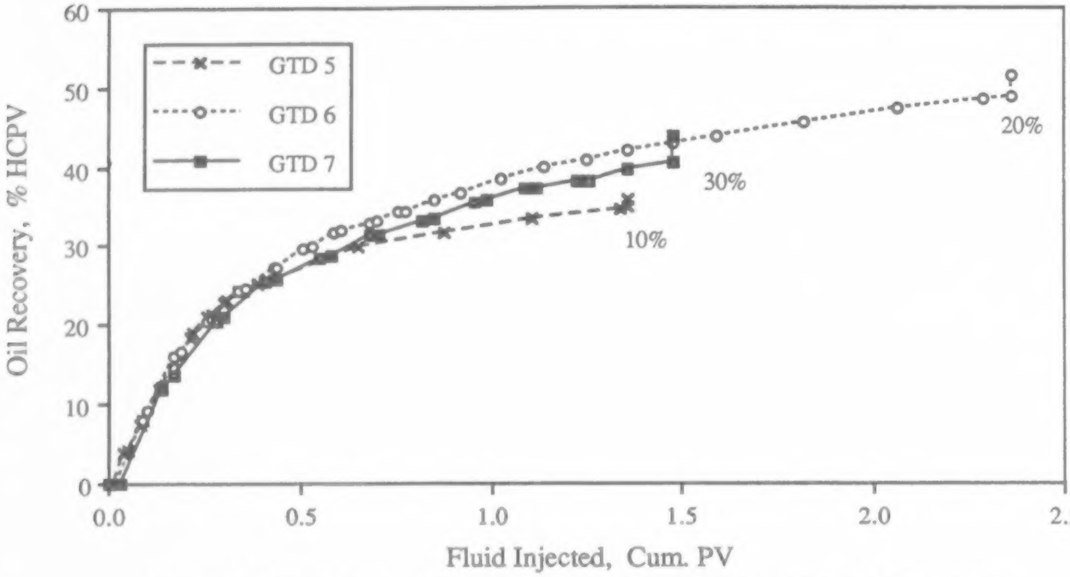


Figure 5.26: Production History of the Two-Dimensional Model Experiments @ 1.0 MPa, 4:1 WAG, 10 Slugs and 2.6 m/d Brine Flow Velocity.

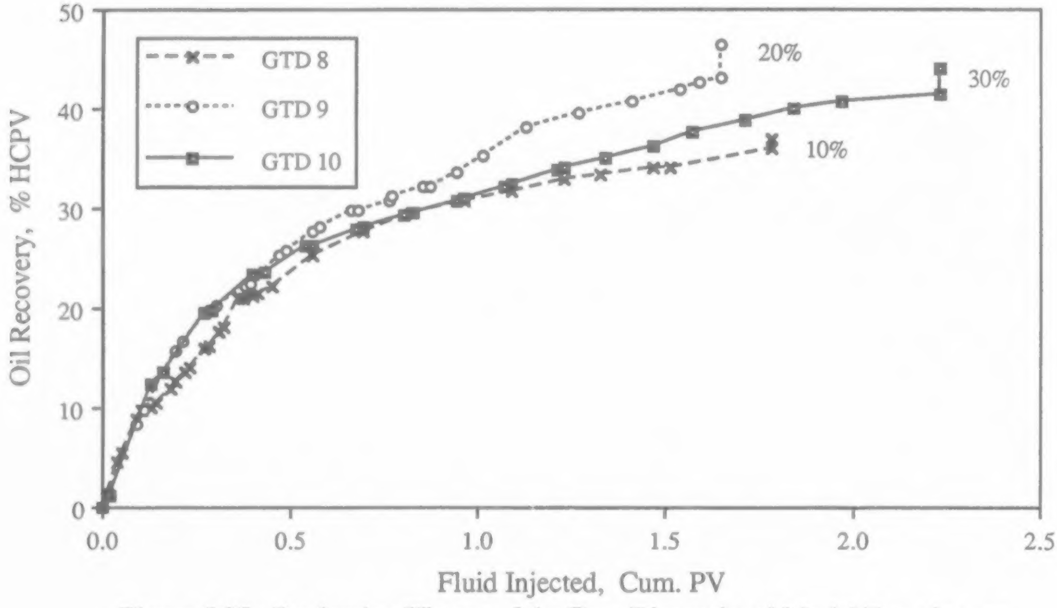


Figure 5.27 : Production History of the Two-Dimensional Model Experiments @ 1.0 MPa, 4:1 WAG, 10 Slugs and 1.3 m/d Brine Flow Velocity.

In an identical study, Runs GTD 8, GTD 9, and GTD 10 were carried out at half the flow velocity of the previous set of experiments, i.e. 1.3 m/d. Again, Run GTD 9 which used a slug size of 20% HCPV of carbon dioxide had the highest oil recovery at 46.4%. This was followed by Run GTD 10 (which utilized a 30% HCPV of carbon dioxide) with a total oil recovery of 44.1%. For Run GTD 8, which utilized a 10% HCPV of carbon dioxide, the experiment yielded a total oil recovery of 36.8%. Figure 5.27 presents the comparison of the production histories of these runs. Figure 5.7 shows the gas-oil ratio curves for the three experiments. The curve corresponding to Run GTD 9 appears to have the least fluctuations, thus indicating efficient carbon dioxide utilization.

Figures 5.15-5.17 illustrate the bar diagrams of the carbon dioxide requirement and carbon dioxide retention for the above-mentioned experiments. When the 20% HCPV slug size is compared to the 10% and 30% HCPV slug sizes, the carbon dioxide requirement is low and is considered economically favourable.

5.2.2 Linear Model Experiments

All of the linear model runs were conducted at 2.5 MPa, with a WAG ratio of 4:1, and 10 slugs of carbon dioxide and water. Runs LC 30 through LC 36 (Table 5.2) examined the effect of pressure, for different slug sizes, for a constant flow velocity (0.984 m/d).

5.2.2.1 Effect of Slug Size

In Run LC 30, a 89% HCPV slug of carbon dioxide was injected. This run was conducted to establish if there would be an appreciable increase in oil recovery when injecting a large slug of carbon dioxide. The oil viscosity was 1055 mPa.s and the initial oil saturation at irreducible water saturation was 90.2% pore volume.

The oil recovery during the carbon dioxide WAG process was 47.2%, and there was no oil recovery from the waterflooding stage as the economic limit of 20:1 had already been reached. The recovery for the blowdown phase was 3.0%, giving a total oil recovery of 50.2% (Fig. 5.28).

The produced gas-oil ratios were small at the early stages of the flood, although the gas volumes were high. Later in the experiment, large volumes of gas were produced, resulting in a very high production rate at gas breakthrough. The large volume of gas must have accumulated in the model throughout the run and, when produced all at once, would

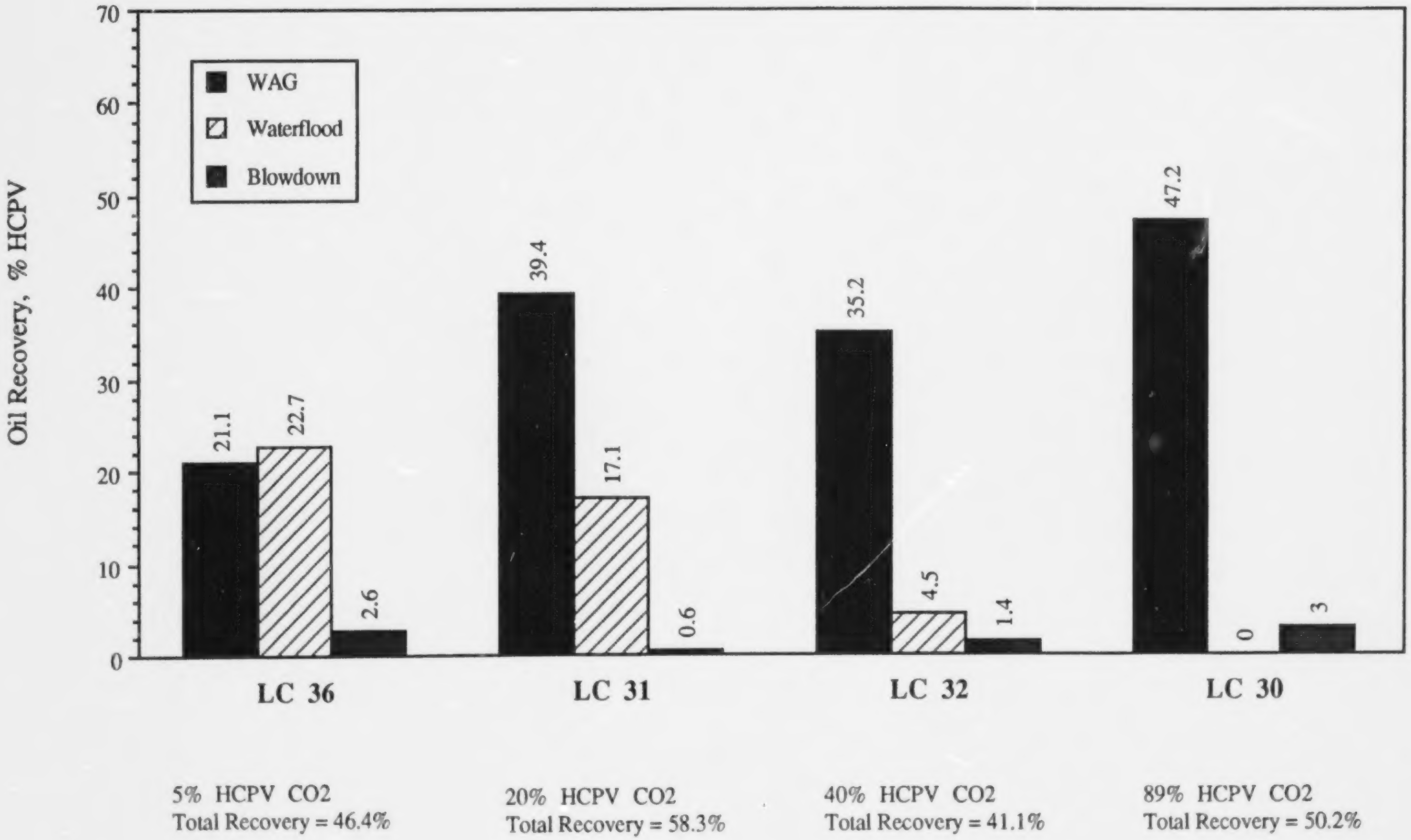


Figure 5.28: Linear Model Experiments @ 2.5 MPa, 4:1 WAG and 10 Slugs.

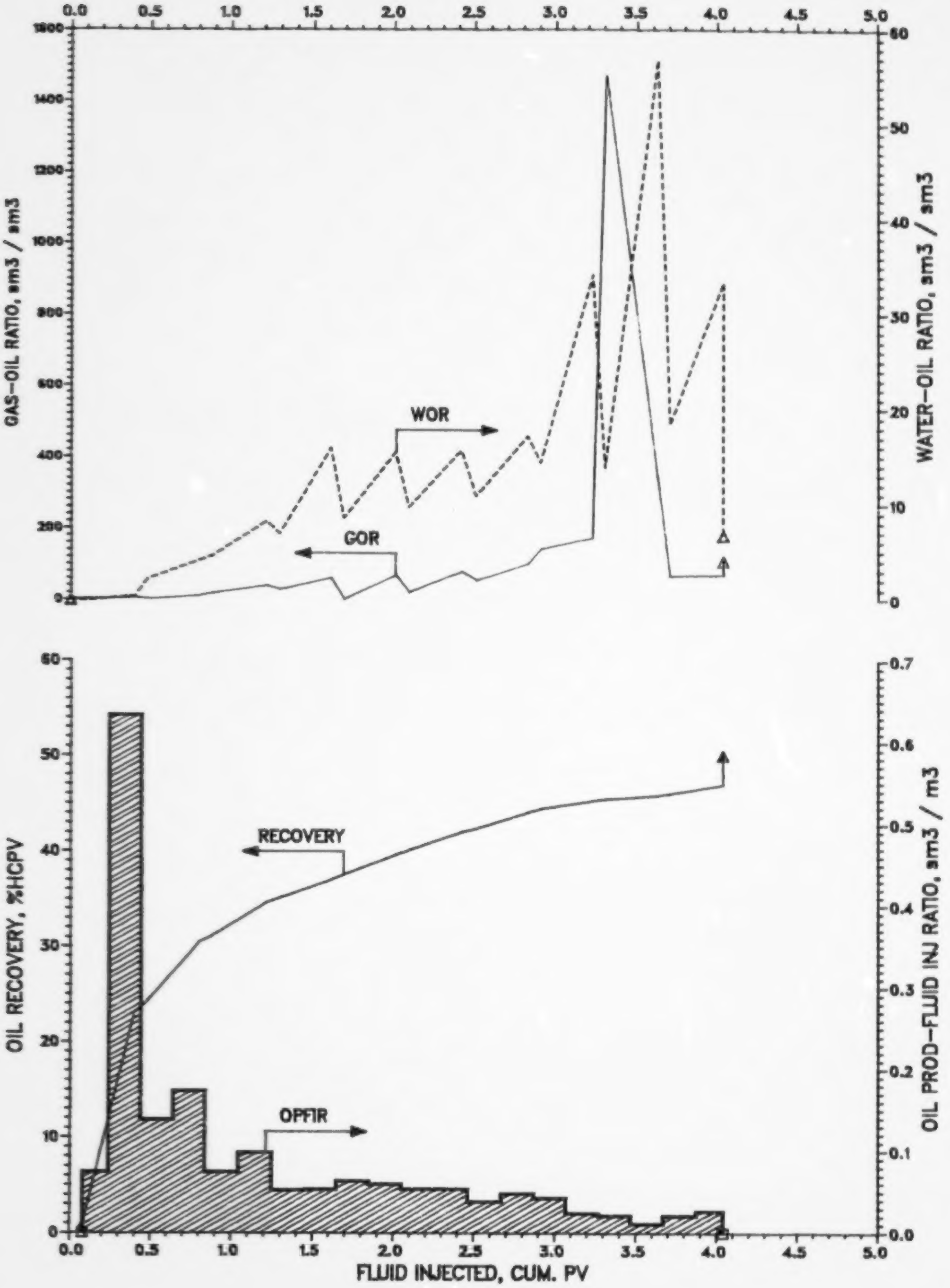
have resulted in gas fingering. The gas was not utilized efficiently as the oil recovery after that did not show any appreciable effect. The water-oil ratio shows that the water breakthrough did not occur until 0.5 pore volume of water had been injected, by which time a major portion of the oil had already been recovered as shown by the OPFIR curve. The production history plots for Runs LC 30, LC 31, LC 32, and LC 36 are shown in Figs. 5.29, 5.31, 5.33, and 5.35, respectively, while the oil recovery distribution plots are shown in Figs. 5.30, 5.32, 5.34, and 5.36, respectively. Figure 5.37 is a comparison of the production histories of Runs LC 31 and LC 32.

In Run LC 31, a 20% HCPV slug of carbon dioxide was injected. The oil recoveries in the WAG and waterflood phases were 39.4% and 17.1%, respectively. The recovery from the blowdown phase was about 0.6% .

In Run LC 32, a 40% HCPV slug of carbon dioxide was injected. The oil sample was the same as that used in the previous two experiments. The oil recovery for the WAG process was 35.2%, and the recovery for the waterflood was approximately 4.5%, which was followed with a blowdown recovery of 1.4%. From the production history plot of this run (Fig. 5.33), the gas-oil ratio curve at the later stages of the run rose rapidly which indicated an inefficient use of carbon dioxide. Before the early gas and water breakthrough, the oil recovery curve was steep indicating a high oil production rate. At the beginning of the run, the OPFIR curve also had a high value and this gradually decreased after the breakthrough point. The oil recovery plot for this run (Fig. 5.34) also showed that the first slug yielded a high oil recovery.

In Run LC 36, the HCPV of the carbon dioxide injected was 5%; this run was designed to examine the oil recovery resulting from injecting a small volume of carbon dioxide gas. The oil viscosity was 1130 mPa.s, and the initial oil saturation was 91.8%. The oil recovery for the WAG process was 21.1% while that for the waterflood phase was 22.7%. This was followed by a recovery of 2.6% during the blowdown phase.

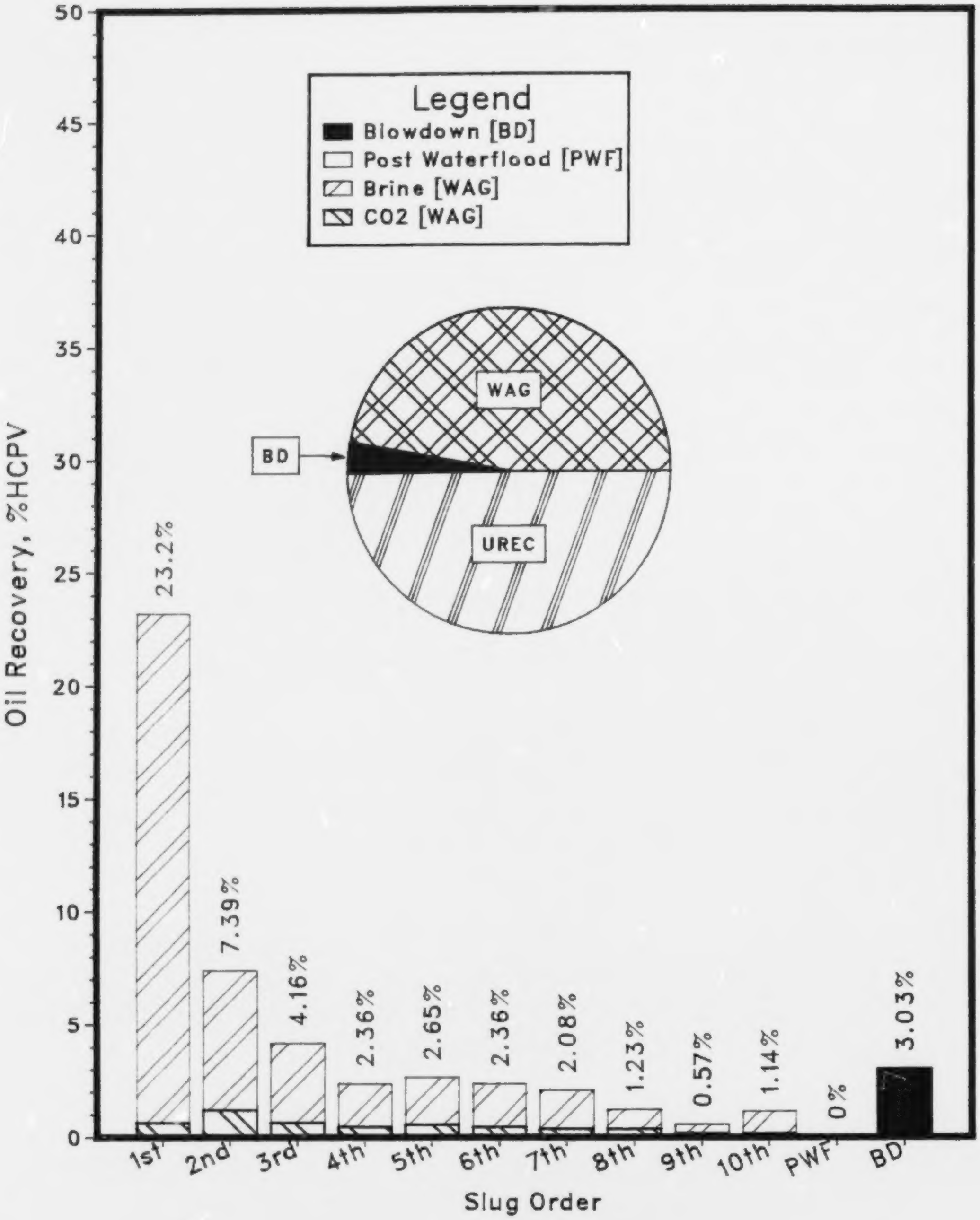
The carbon dioxide requirement for this experiment was only 3.3 sm^3/sm^3, while the carbon dioxide retention was 99.4%. The high retention value indicates that only a very small volume of gas was produced. The gas-oil ratio curve (Fig. 5.35) corroborates that, while the water-oil ratio curve revealed that, after water breakthrough, there was a gradual increase in the volume of water produced until the end of the run. While considering only the WAG phase of the run, the recovery was low when compared to the



NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 37.63 %, k = 11.350 darcies, S_o = 90.24 %, S_{wc} = 9.76 %

[0.89 HCPV CO2 @ 2.5 MPa (1.13 g–mol) 4:1 WAG, 10–Slugs]

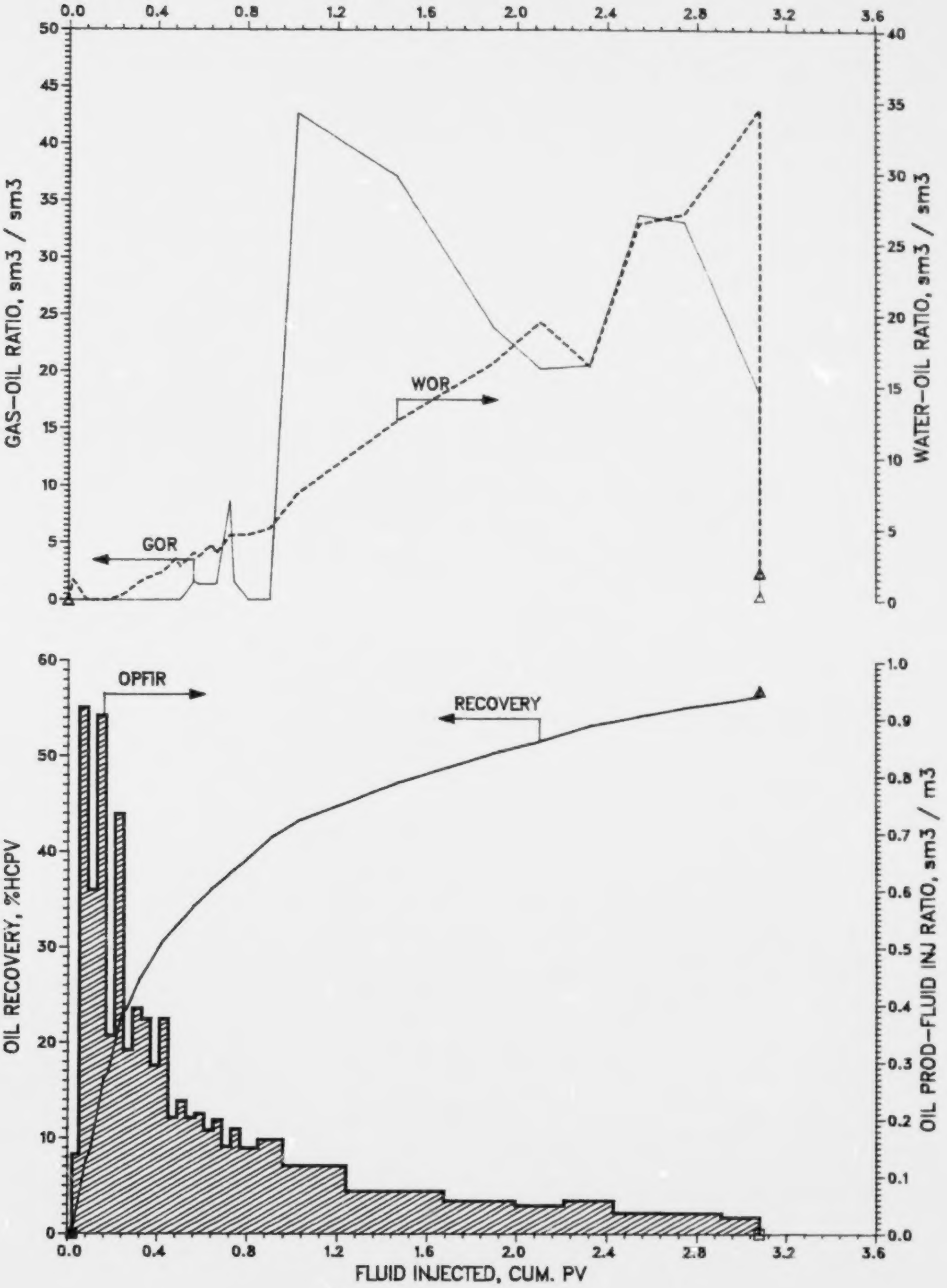
Figure 5.29: Production History of Run LC 30.



NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 37.63 %, k = 11.350 darcies, S_o = 90.24 %, S_{wc} = 9.76 %

[0.89 HCPV CO2 @ 2.5 MPa (1.13 g-mol) 4:1 WAG, 10-Slugs]

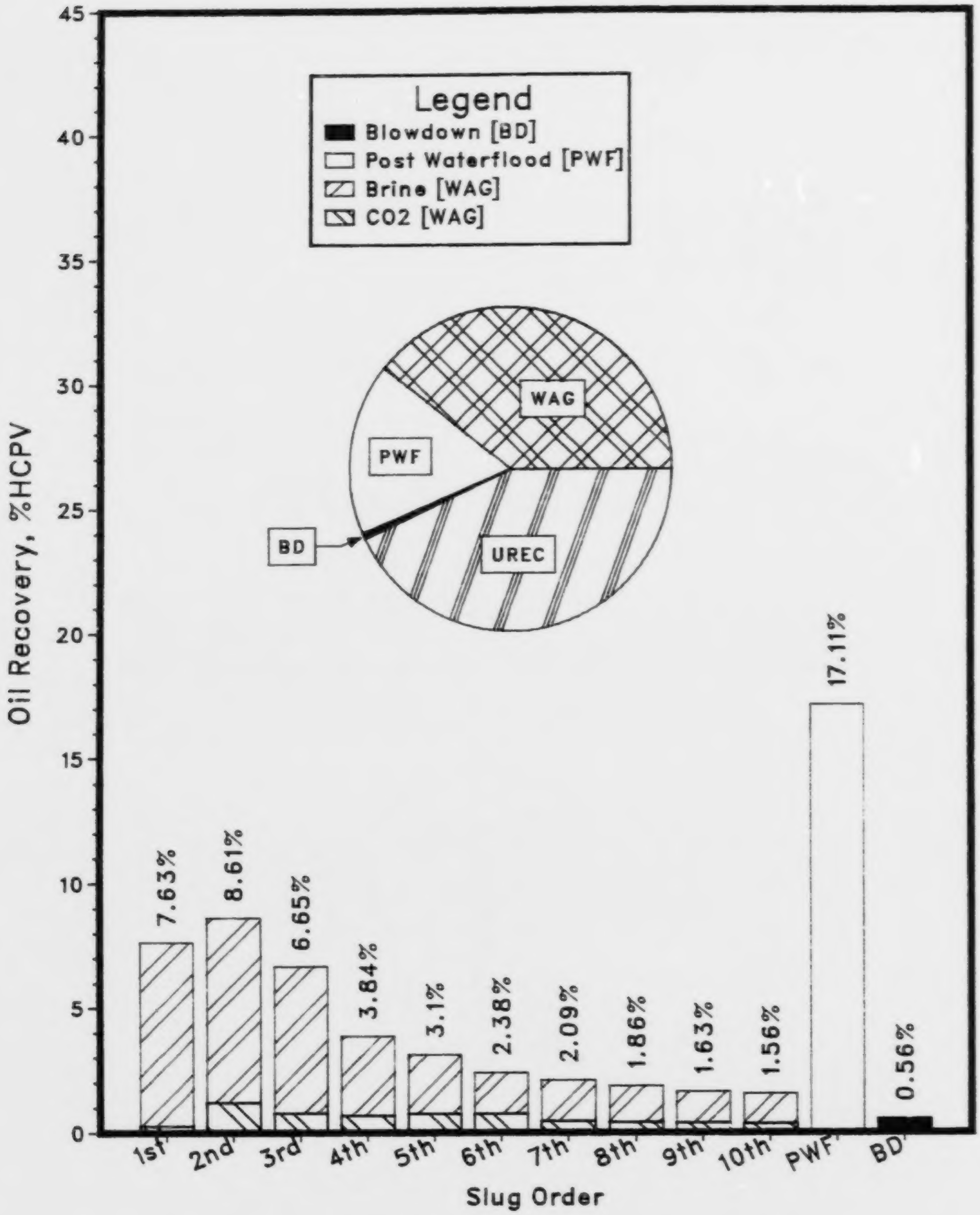
Figure 5.30: Oil Recovery Distribution of Run LC 30.



NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.35 %, k = 11.040 darcies, S_o = 79.35 %, S_{wc} = 20.65 %

[0.20 HCPV CO2 @ 2.5 MPa (0.22 g-mol) 4:1 WAG, 10-Slugs]

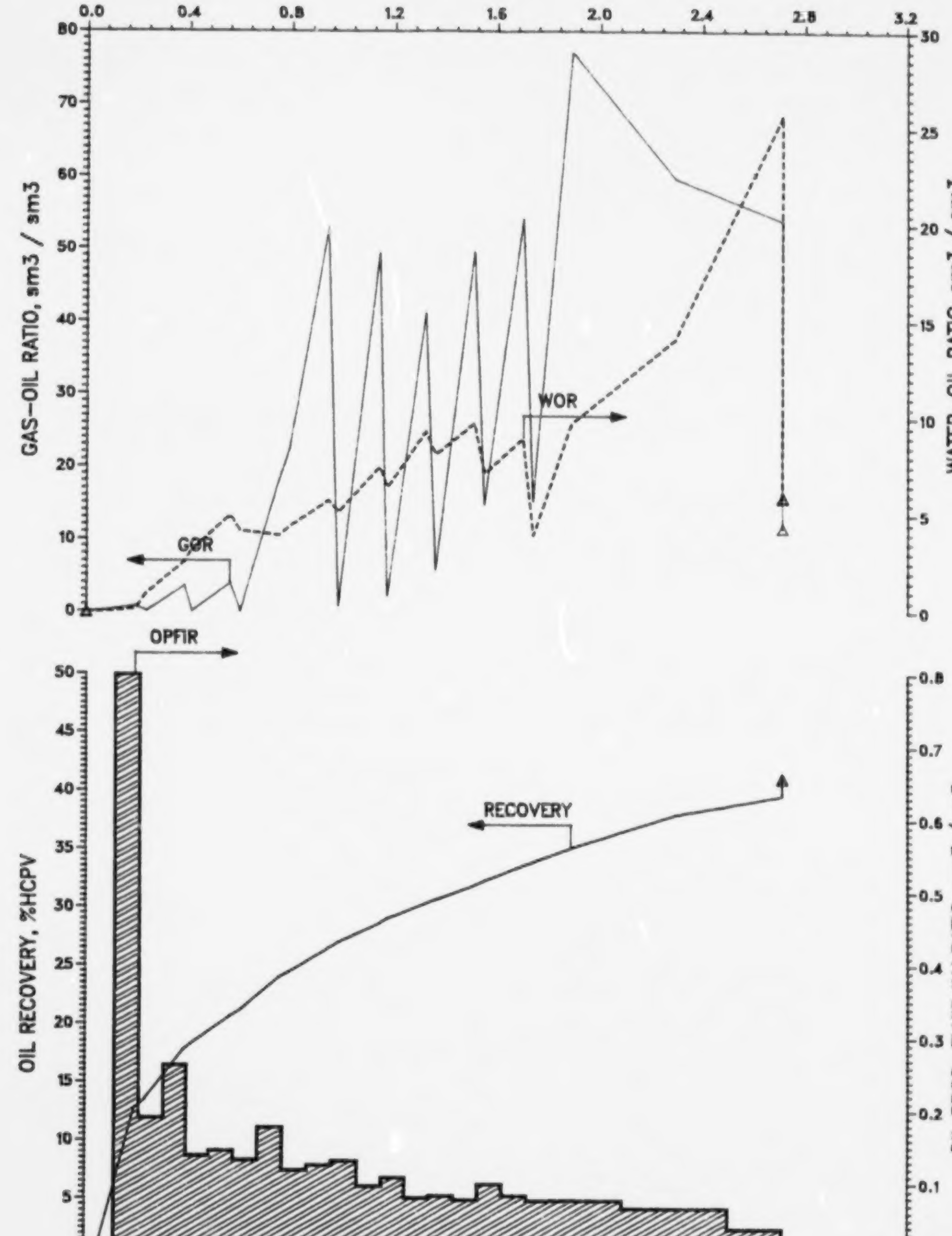
Figure 5.31: Production History of Run LC 31.



NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.35 %, k = 11.040 darcies, S_o = 79.35 %, S_{wc} = 20.65 %

[0.20 HCPV CO2 @ 2.5 MPa (0.22 g-mol) 4:1 WAG, 10-Slugs]

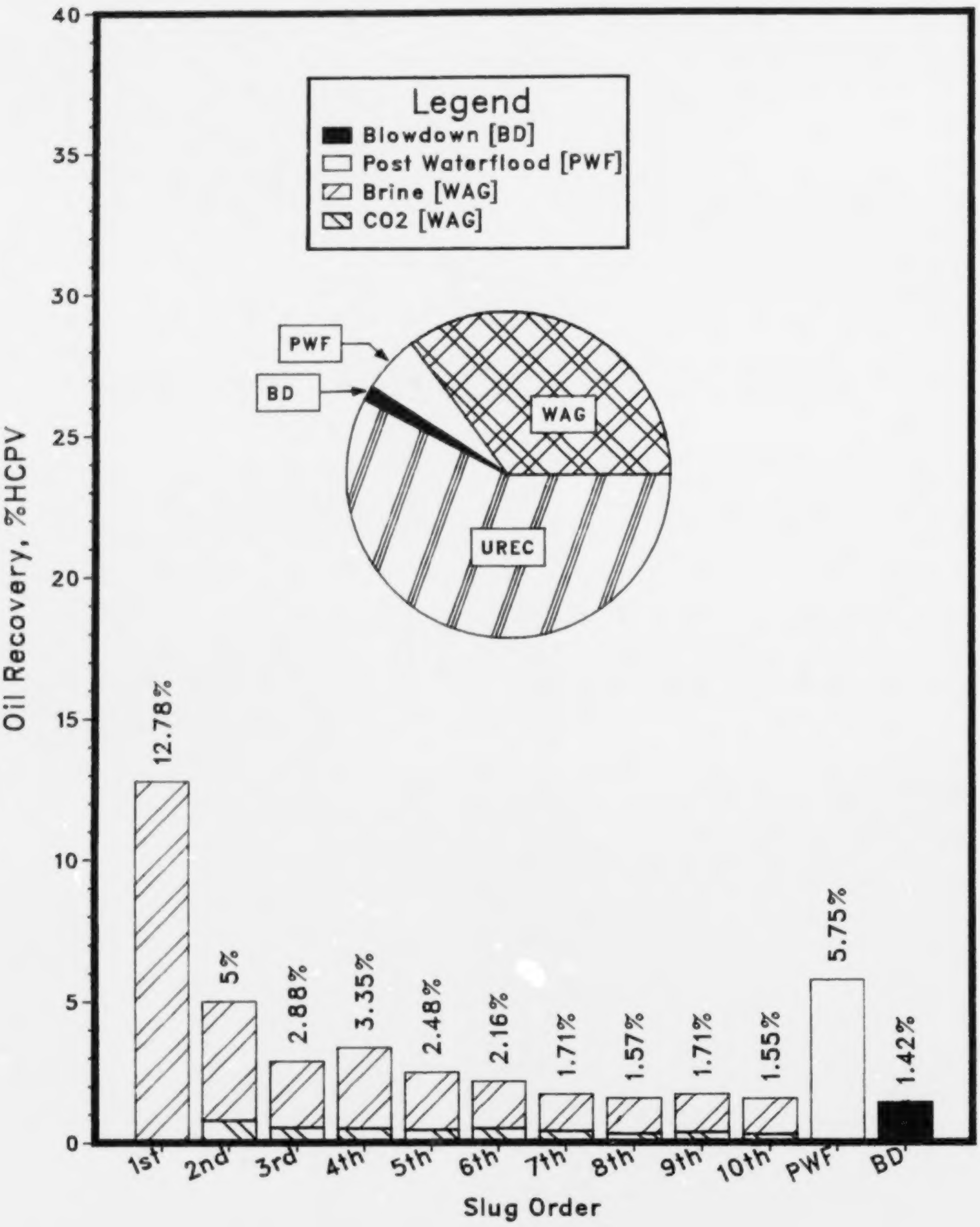
Figure 5.32: Oil Recovery Distribution of Run LC31.



NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 37.63 %, k = 14.130 darcies, S_o = 93.66 %, S_{wc} = 6.34 %

[0.40 HCPV CO2 @ 2.5 MPa (0.53 g-mol) 4:1 WAG, 10-Slugs]

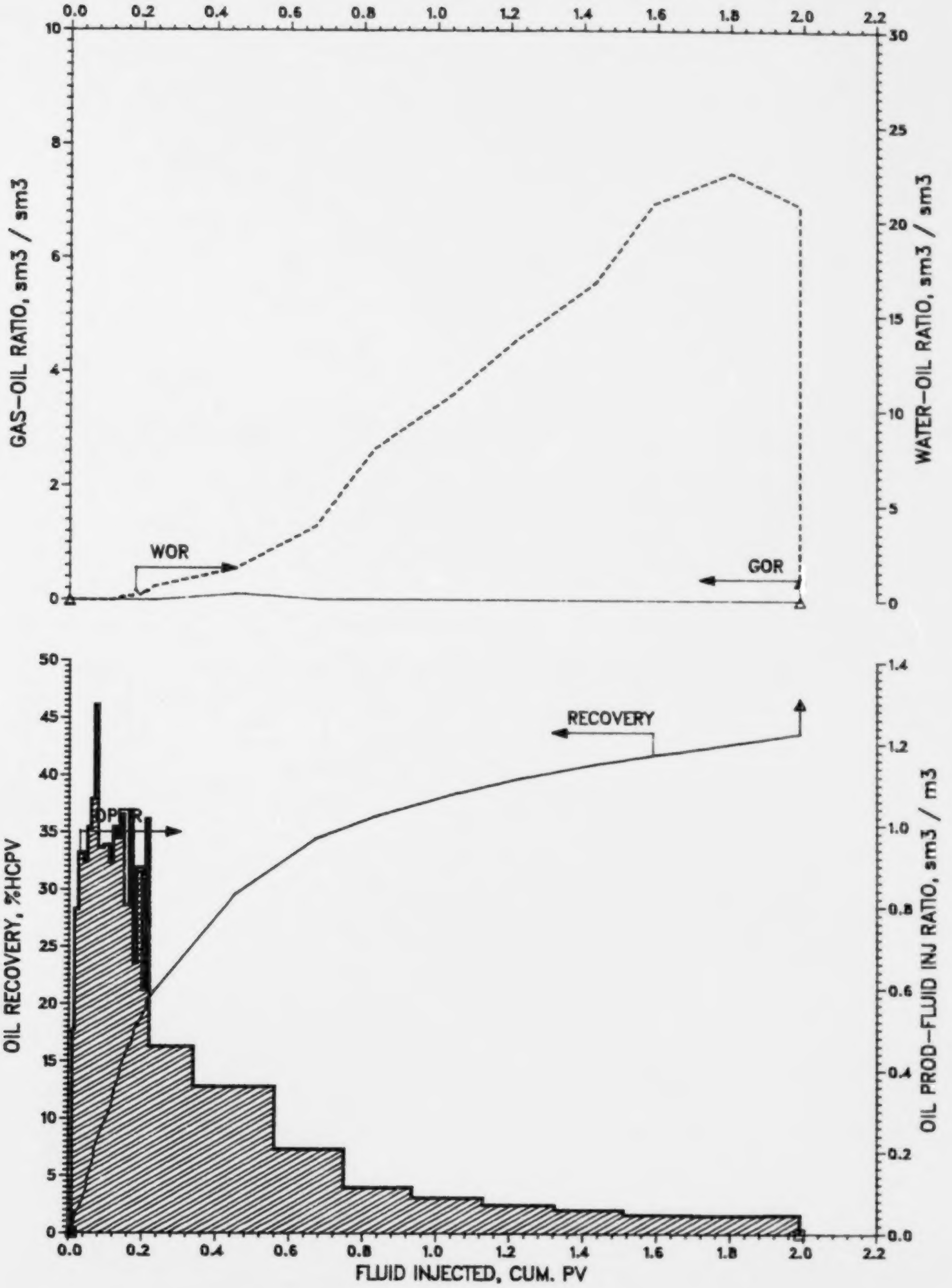
Figure 5.33: Production History of Run LC 32.



NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 37.63 %, k = 14.130 darcies, S_o = 93.66 %, S_{wc} = 6.34 %

[0.40 HCPV CO2 @ 2.5 MPa (0.53 g–mol) 4:1 WAG, 10–Slugs]

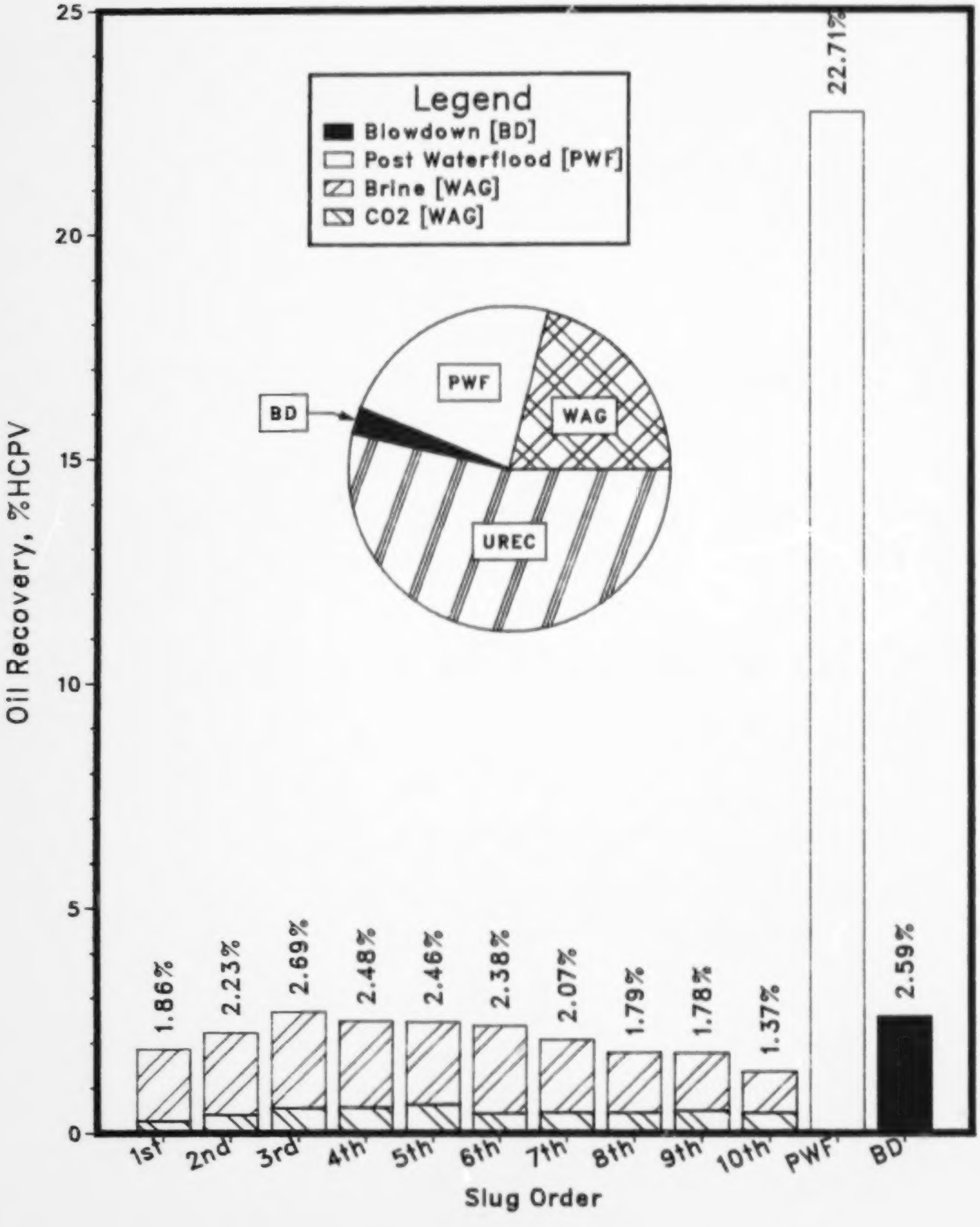
Figure 5.34: Oil Recovery Distribution of Run LC 32.



NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1130.0 mPa.s
ϕ = 37.15 %, k = 11.170 darcies, S_o = 91.83 %, S_{wc} = 8.17 %

[0.05 HCPV CO2 @ 2.5MPa (0.064g–mol) 4:1 WAG,10 Slugs]

Figure 5.35: Production History of Run LC 36.



NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1130.0 mPa.s
ϕ = 37.15 %, k = 11.170 darcies, S_o = 91.83 %, S_{wc} = 8.17 %

[0.05 HCPV CO2 @ 2.5MPa (0.064g–mol) 4:1 WAG,10 Slugs]

Figure 5.36: Oil Recovery Distribution of Run LC 36.

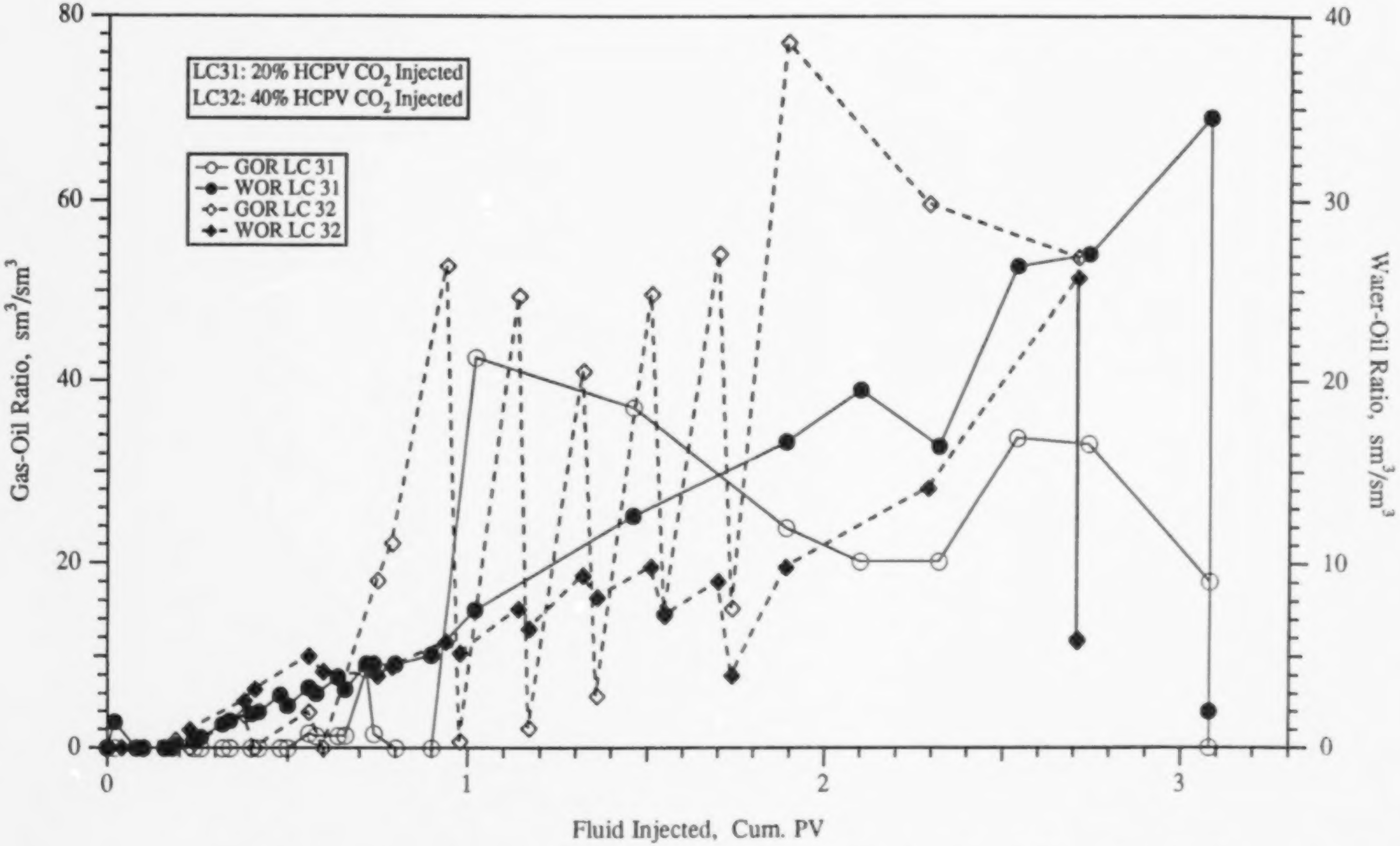


Figure 5.37 : Comparison of the GOR and WOR Production Histories of Run LC31 and Run LC32 (Linear Model Experiments).

other runs as shown in Fig. 5.28, but the overall recovery was 46.4% which was much higher than the total recovery of Run LC 32 (41.1%), employing a 40% HCPV slug.

Figures 5.28, 5.38 and 5.39 show the oil recovery, production history, carbon dioxide requirement and retention curves for the above runs. Referring to the production history curves (Fig. 5.29) of Run LC 30 (89% carbon dioxide slug), notice that a large scale is used for the gas-oil ratio axis. There was a considerable difference between the performance of this experiment and the other three experiments. This can be attributed possibly to the large slug size used for the experiment. When considering only the recovery from the WAG phase, Run LC 30 has the highest WAG recovery value (47.2%). However, when considering the total recoveries, the total recovery (57%) using a 20% HCPV slug of carbon dioxide (Run LC 31) was higher than that of Run LC 30 (50.2%) which utilized a 89% HCPV slug of carbon dioxide. The recovery for the 20% HCPV slug was also higher than that of Run LC 32 (41.1%) which utilized a 40% HCPV slug of carbon dioxide. It thus seems that the 20% HCPV slug was optimal among the four slugs tested. It also gave the highest oil production rate (initial slope of the curve in Fig. 5.38). The largest slug of 89% led to a high carbon dioxide requirement and also a high producing gas-oil ratio and low retention.

It is interesting to consider the relative contributions of the WAG phase (Fig. 5.28) in relation to the cumulative recovery curve (Fig. 5.38). It is evident that this phase alone does not provide a complete explanation of the process efficiency.

5.2.2.2 Tertiary Recovery Experiment

A tertiary recovery experiment was performed by initially conducting a waterflood in the model until a water-oil ratio of 20:1 was reached. The purpose of this run was to ascertain if the carbon dioxide WAG process can produce incremental oil after a waterflood. At this point, the WAG process was initiated for incremental recovery. After this, a waterflood phase was initiated if necessary, depending on the water-oil ratio, to recover any remaining mobile oil. This was followed by the blowdown phase.

A tertiary recovery Run LC 34 was conducted at 2.5 MPa in the linear model. This experiment recovered 41.5% of the initial oil-in-place. This was followed by the WAG and blowdown phases which produced an additional 2.9% and 17.3%, respectively. The final waterflood was not conducted as the water-oil ratio after the WAG process had already reached 20:1.

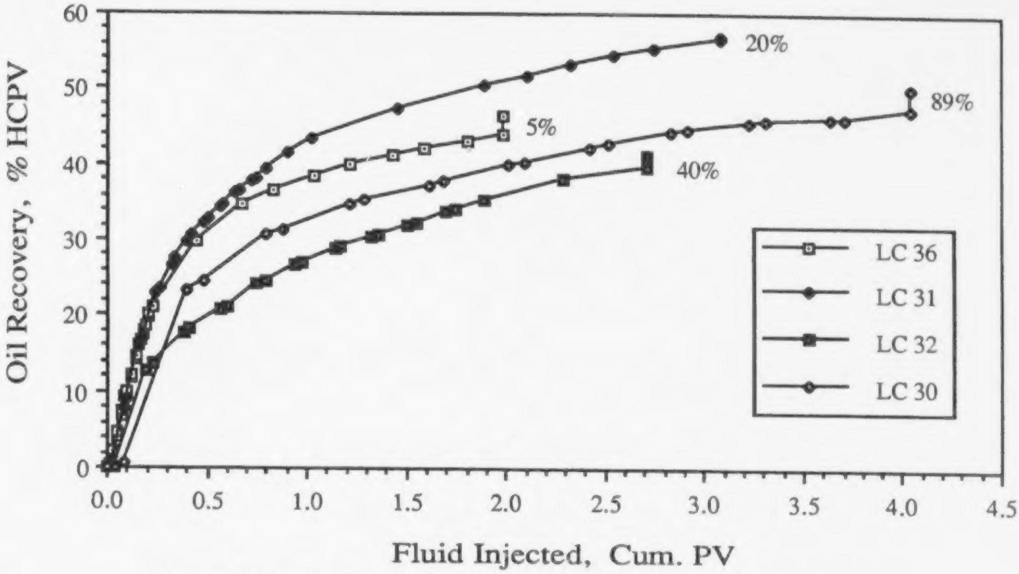


Figure 5.38: Production History of the Linear Model Experiments @ 2.5 MPa, 4:1 WAG and 10 Slugs.

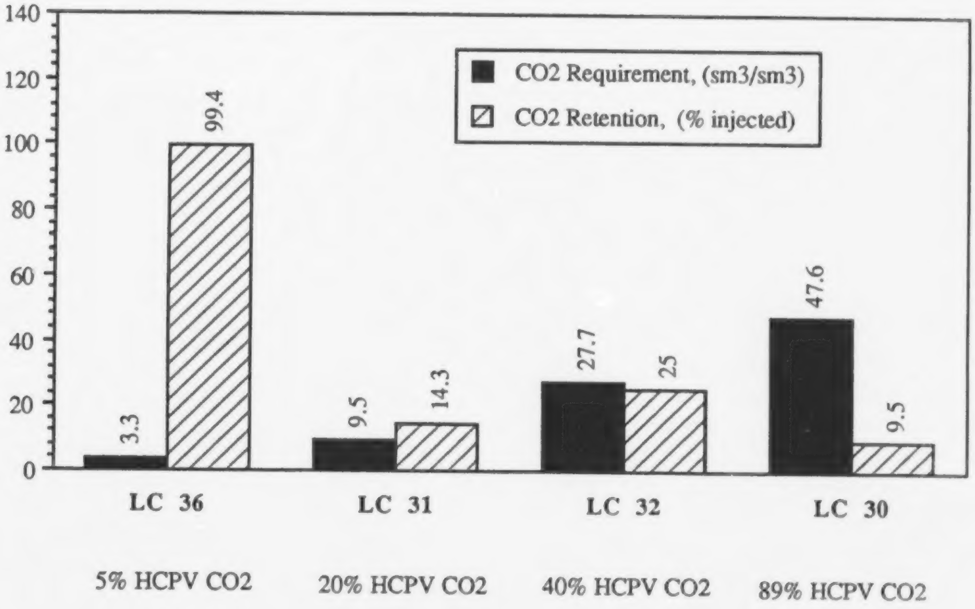


Figure 5.39: Linear Model Experiments @ 2.5 MPa, 4:1 WAG and 10 Slugs.

Clearly, the carbon dioxide WAG flooding process was able to mobilize residual oil. The increased recovery could be attributed to oil swelling so that the average oil saturation was increased above the residual oil saturation. Figure 5.40 shows the oil recovery distribution in the tertiary recovery mode for Run LC 34. Essentially, the major portion of the oil recovered in the tertiary run was from the blowdown phase. In the study conducted by Rojas, it was found that the blowdown phase in tertiary oil recovery experiments accounted for approximately 13.5%-40% of the total tertiary oil production in the runs using Aberfeldy oil. Figure 5.41 shows the production history plot of the tertiary run which was made up of Runs LC 34 and LC 35. Gas was produced only during the blowdown phase as the volume of gas injected during the WAG process was very small. After the water breakthrough, the volume of water gradually increased during the initial waterflood and then there was some fluctuation during the WAG phase. The OPFIR curve indicated that a large oil bank formed after the water breakthrough. This was represented by the increasing water-oil ratio curve which corresponded to that point, and the high oil production rate as shown by the recovery curve.

5.2.3 Live Oil Experiments

The live oil experiments were conducted to investigate the effect of gas initially in solution on oil recovery. All the runs were conducted at 1.0 MPa, at a WAG ratio of 4:1, with 10 slugs of carbon dioxide and water. A total of seven runs were conducted using live oil.

An experimental procedure was developed to produce the required quantities of live oil necessary for each experiment. A maximum of 3.78 liters could be prepared in one batch. A description of the live oil preparation is given in Section 4.1.1.1 with a schematic diagram of the equipment used.

The first experiment to use a live oil sample was Run LC 37. The procedure for calculating the pore volume and permeability were the same as in the previous experiments. When saturating the model, the model was first pressurized to the experimental pressure using reservoir water. Then the model was saturated with the live oil sample until droplets of oil appeared at the production end of the model. The hydrocarbon pore volume was calculated to be equal to the volume of water displaced from the model. The oil saturation was thus equal to the hydrocarbon pore volume calculated. In this run, the WAG, waterflood, and blowdown phases produced oil recoveries of 43.4, 14.4, and 8.63%, respectively. Figure 5.42 is the production history plot of Run LC 37 and Fig. 5.43 is the oil recovery

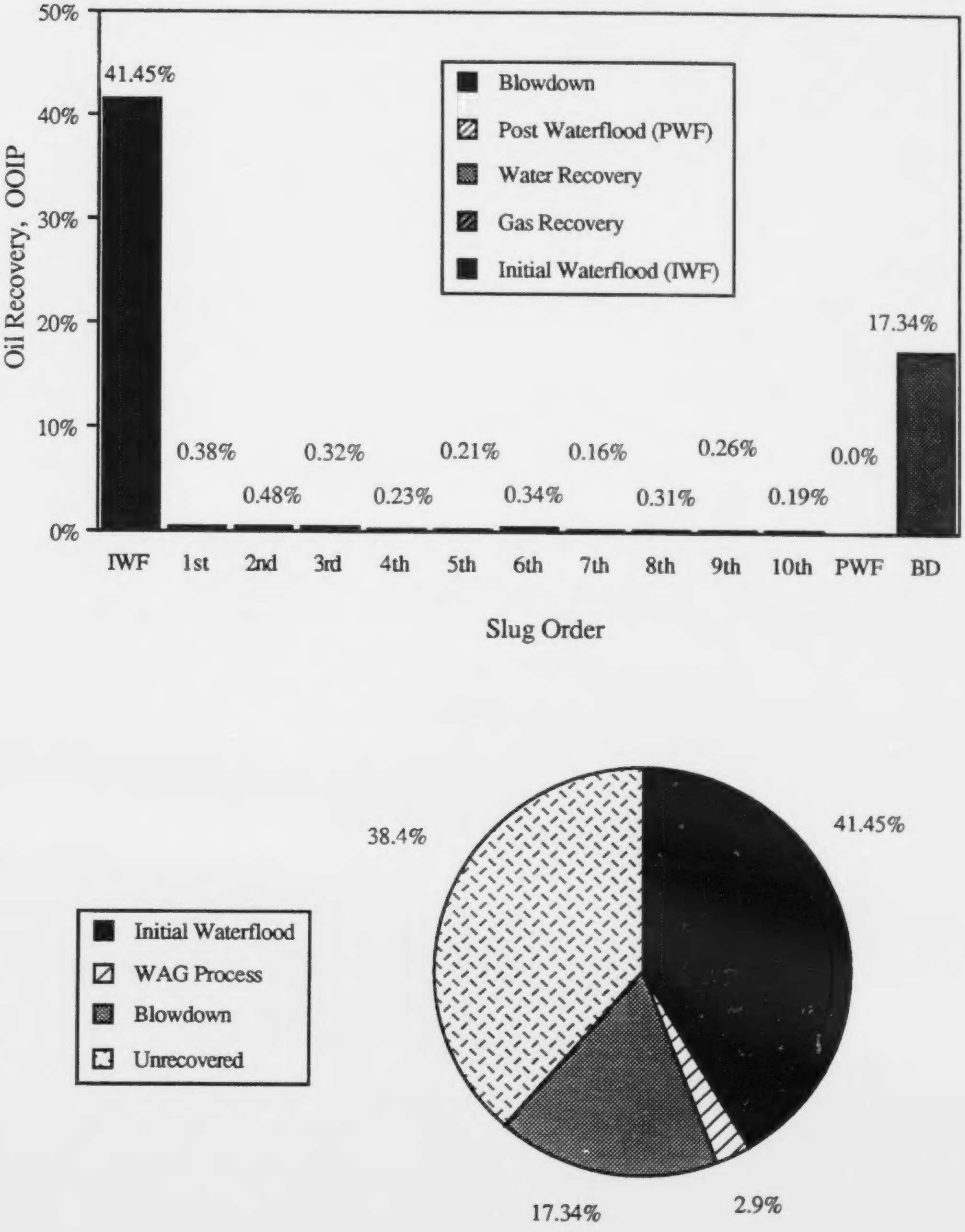
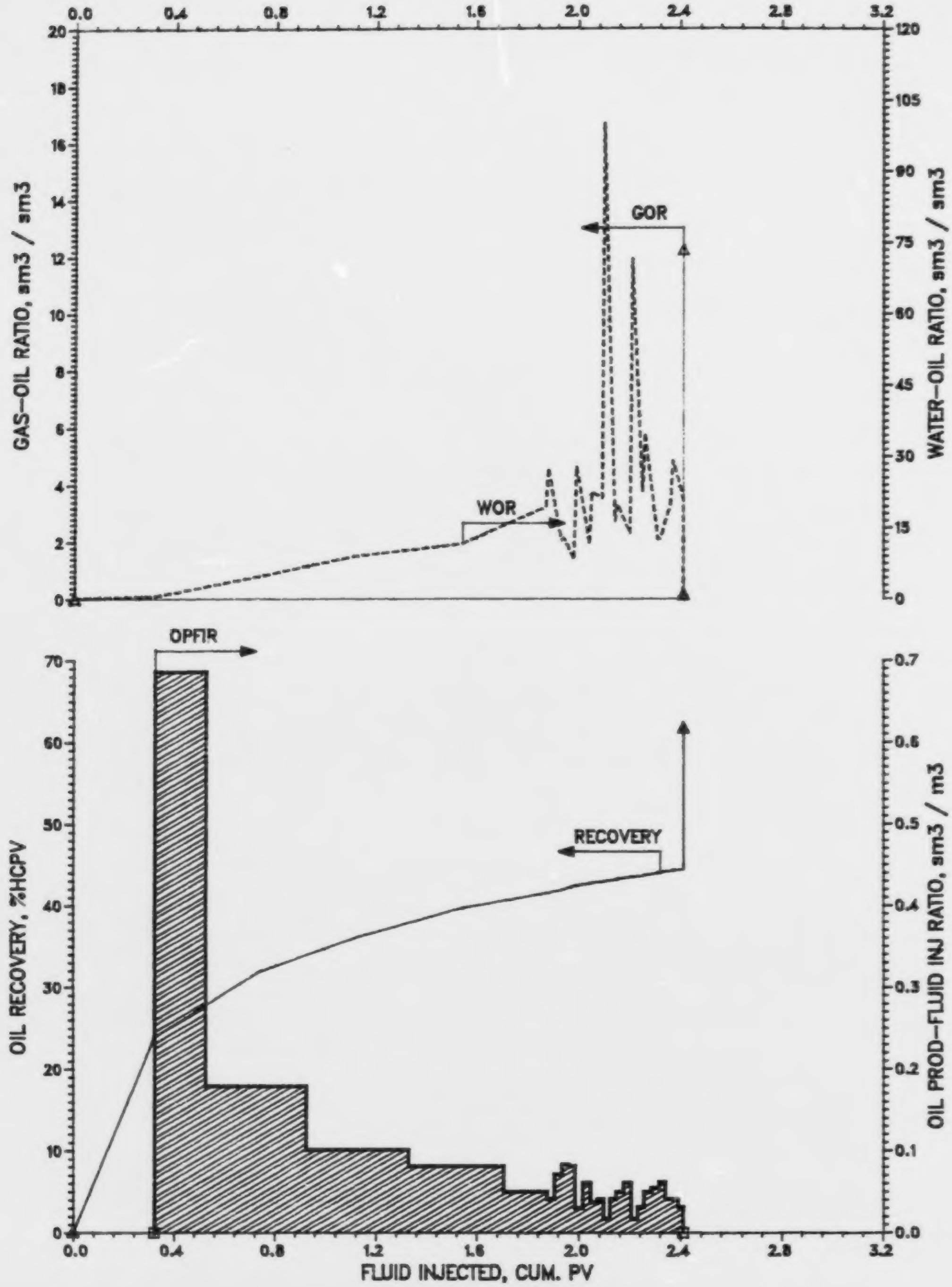


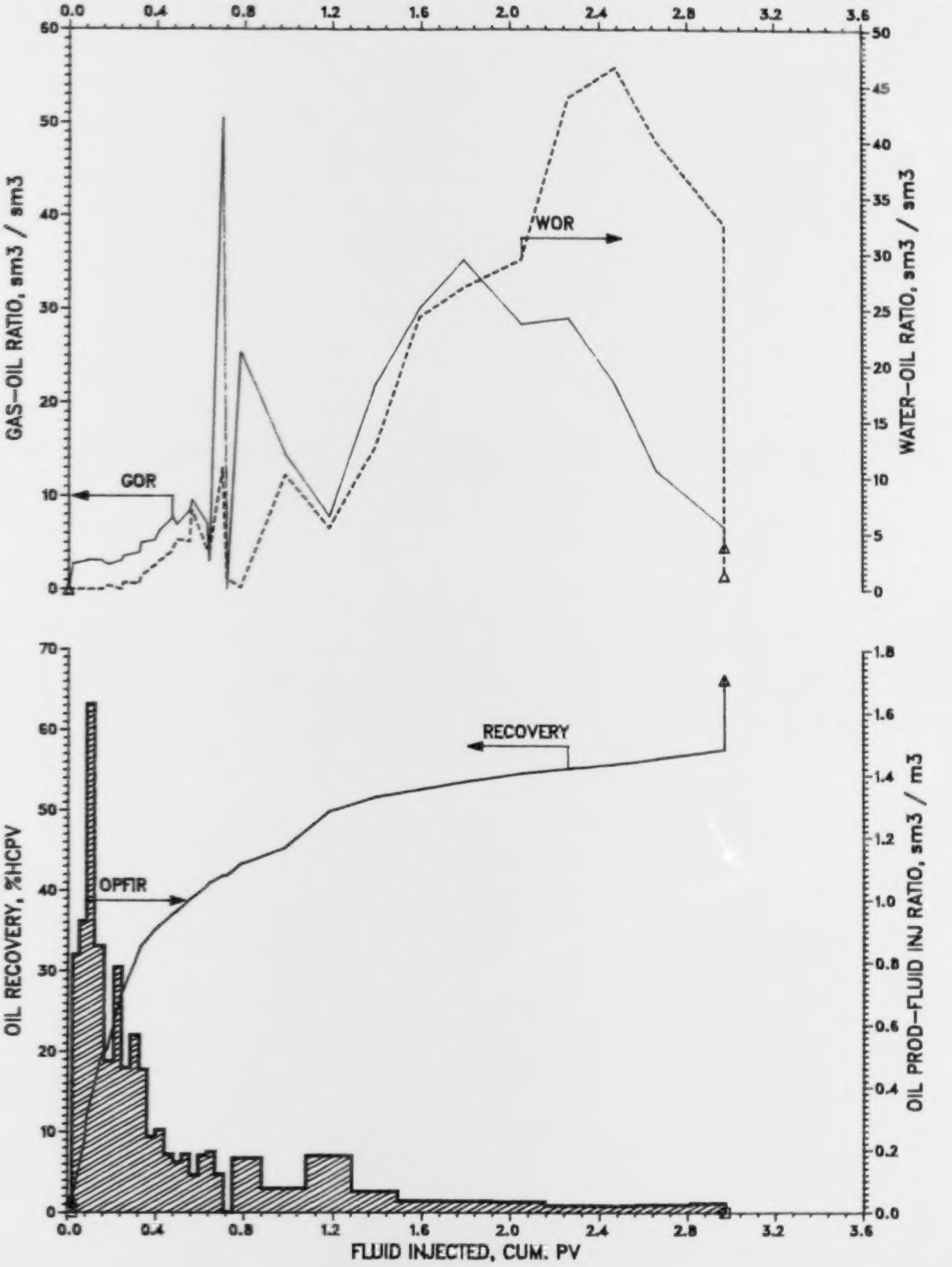
Figure 5.40: Tertiary Oil Recovery Distribution (Runs LC 34 & LC 35).



NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 882.0 mPa.s
ϕ = 36.47 %, k = 9.910 darcies, S_o = 92.54 %, S_{wc} = 7.46 %

[2.02 HCPV WF=>0.20 RHCPV CO2 @ 2.5MPa (0.24g–mol) 4:1 WAG,10 Slugs]

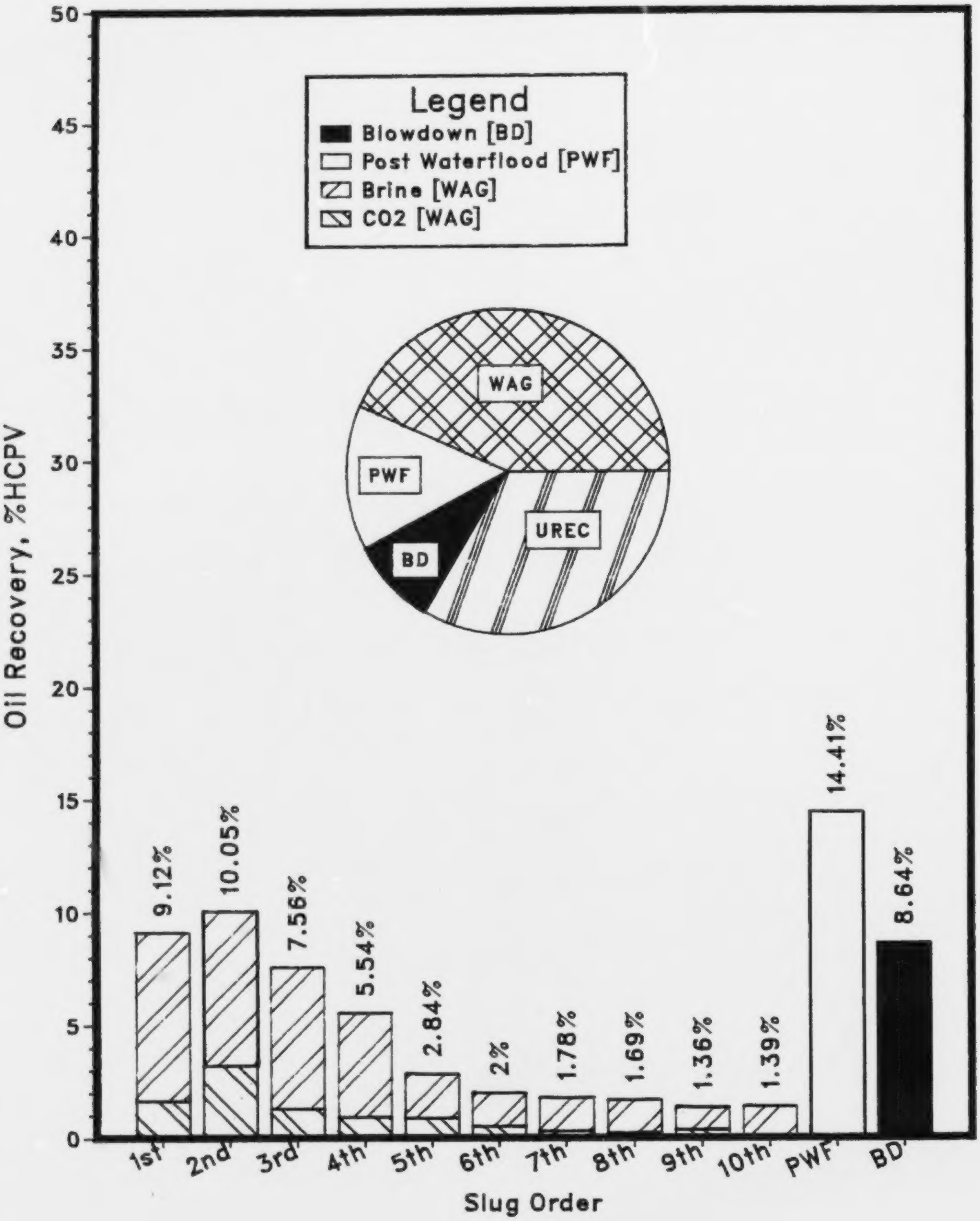
Figure 5.41: Production History of Run LC34 & LC35.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s
ϕ = 36.73 %, k = 9.180 darcies, S_o = 88.70 %, S_{wc} = 11.30 %

[0.2 HCPV CO2 @ 1.0 MPa (0.076 g–mol) 4:1 WAG,10 Slugs, LIVE OIL]

Figure 5.42: Production History of Run LC 37.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s
ϕ = 36.73 %, k = 9.180 darcies, S_o = 88.70 %, S_{wc} = 11.30 %

[0.2 HCPV CO2 @ 1.0 MPa (0.076 g-mol) 4:1 WAG,10 Slugs, LIVE OIL]

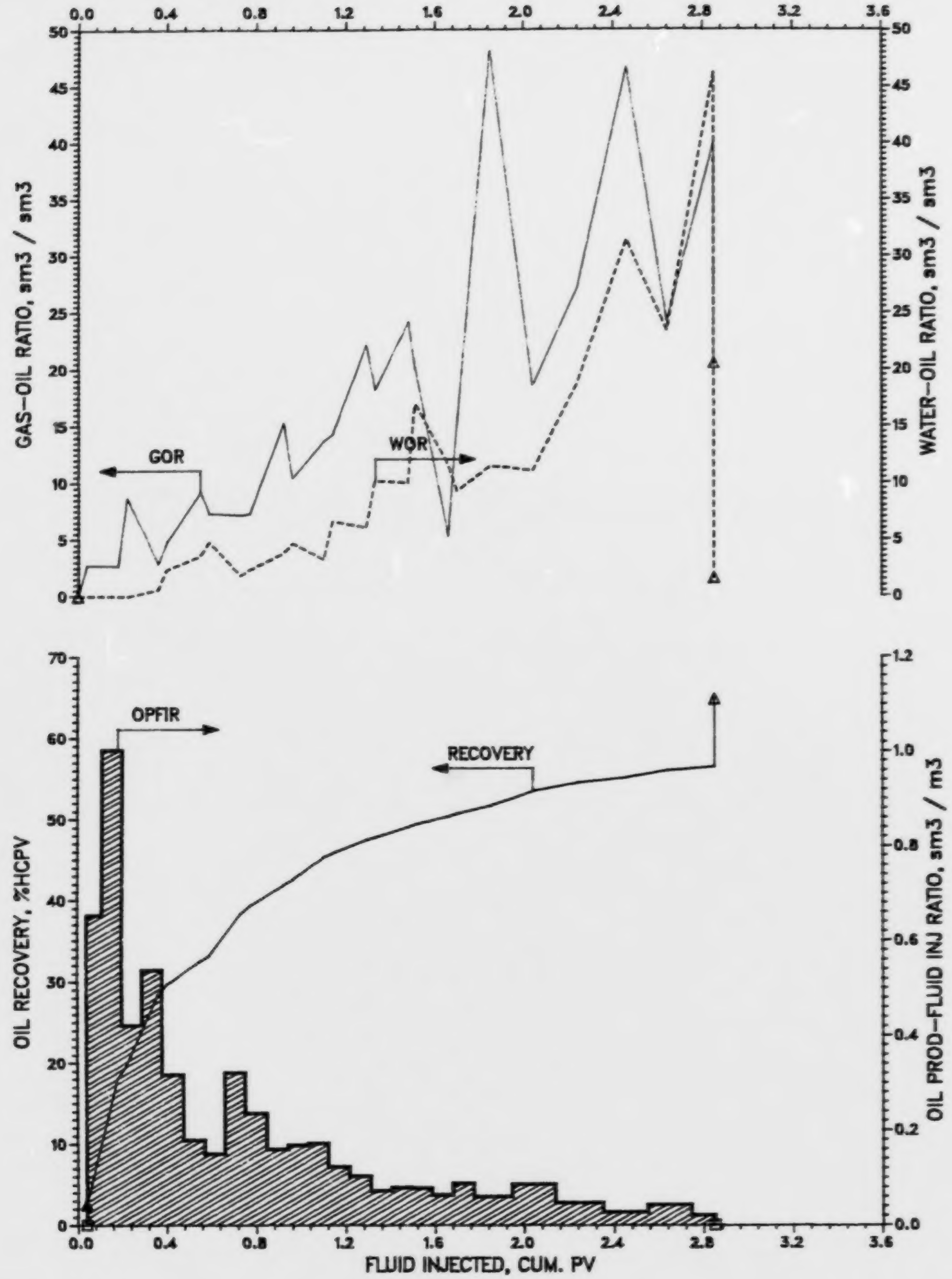
Figure 5.43: Oil Recovery Distribution of Run LC 37.

distribution plot. The gas-oil ratio curve showed that gas breakthrough occurred almost immediately after carbon dioxide injection started. This behaviour was quite different from the previous runs using dead oil. The difference was that in this run the oil was saturated with methane. Carbon dioxide will dissolve in the oil and cause methane to be released from the solution. As a result, the stripping of the solution gas will occur as the solubility of carbon dioxide gradually increases. The first few slugs of the 10 injected, produced a large volume of oil and also the blowdown phase produced a higher volume of oil. This was due to the liberation of all excess gas in solution, when the pressure in the model was reduced to atmospheric pressure.

In Run LC 38, a 40% HCPV slug of carbon dioxide was injected, keeping other parameters constant. The oil recovered from the WAG process alone was 51.8%, followed by recoveries of 4.8 and 8.14% during the waterflood and blowdown phases, respectively. This WAG recovery was the highest for all the live oil runs conducted as the volume of gas injected was the largest (40% carbon dioxide slug). Figures 5.44 and 5.45 are the production history and oil recovery distribution plots for this experiment. The gas breakthrough in this run again occurred at the very start, and the gas-oil ratio curves rose more rapidly, showing that the gas was not efficiently utilized. A large oil recovery was obtained before water breakthrough and also the blowdown recovery was significant as most of the gas injected during this run (40% carbon dioxide slug) was released during this phase.

In Run LC 39, a 10% HCPV slug of carbon dioxide was injected, the other parameters being constant. The oil recovered from the WAG process was 33% followed by the waterflood and blowdown recoveries of 26.7 and 2.9%, respectively. From the production history curve (Fig. 5.46), it is seen that at water breakthrough, the oil production rate increased, indicating banking of oil. Thereafter, the oil recovery decreased. The oil recovery plot (Fig. 5.47), showed that during the WAG phase the first three slugs produced a large volume of oil. As the water-oil ratio was very low at the end of the WAG phase, the waterflood phase recovered a large volume of oil (26.7%) and the blowdown recovery was low for this run as the major portion of oil had already been recovered.

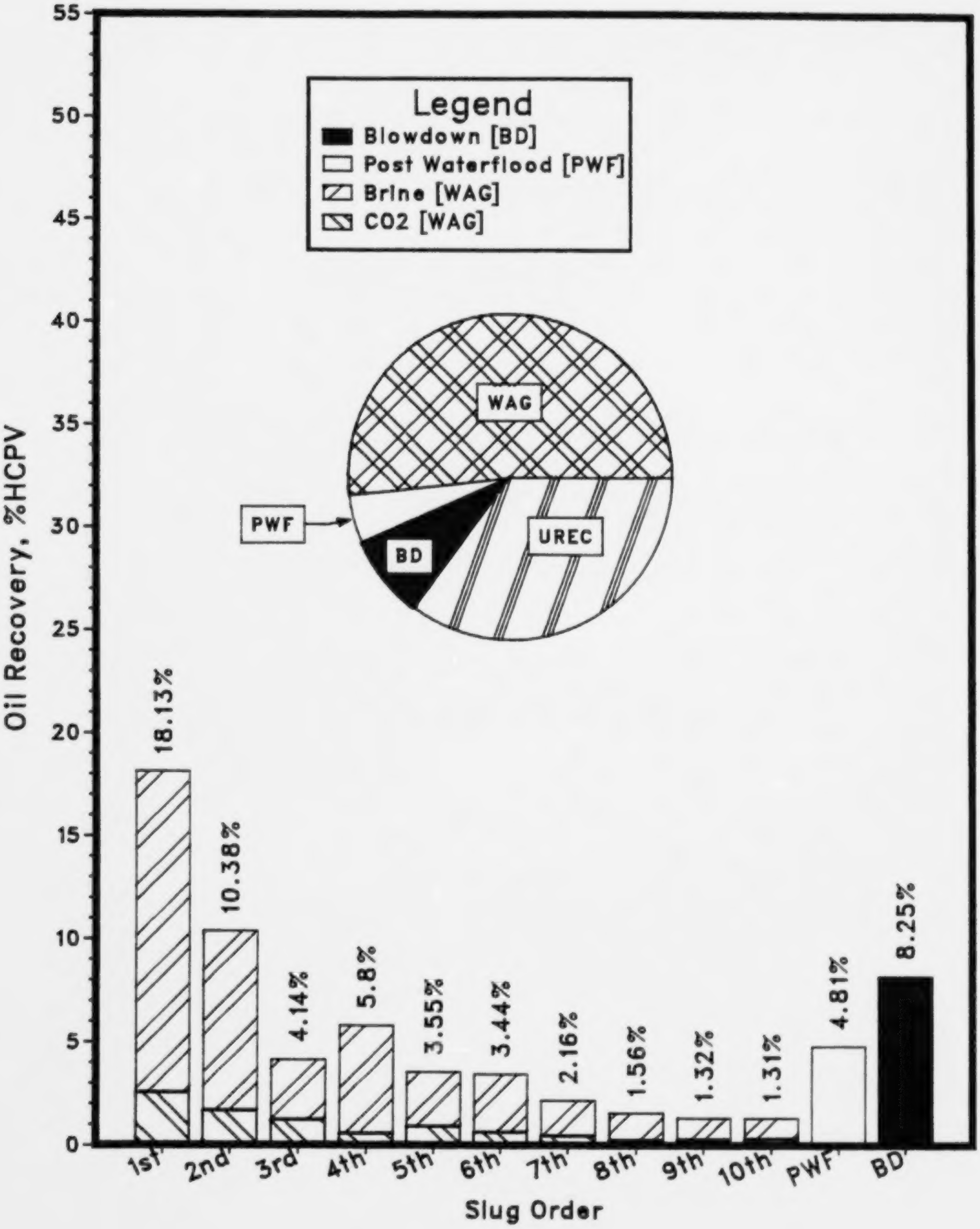
The next experiment, Run LC 40, was similar to Run LC 39 except that the slug volume was 20% HCPV. The recovery from the WAG phase was 40% and the oil recovery from the waterflood and blowdown phases were 17.0% and 6.61%, respectively. From the production history curve (Fig. 5.48), the gas-oil ratio indicates that gas breakthrough occurred at the beginning of the run as in the previous live oil runs. The OPFIR curve



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s
ϕ = 39.85 %, k = 11.800 darcies, S_o = 90.54 %, S_{wc} = 9.46 %

[0.4 HCPV CO2 @ 1.0 MPa (0.198 g-mol) 4:1 WAG,10 Slugs, LIVE OIL]

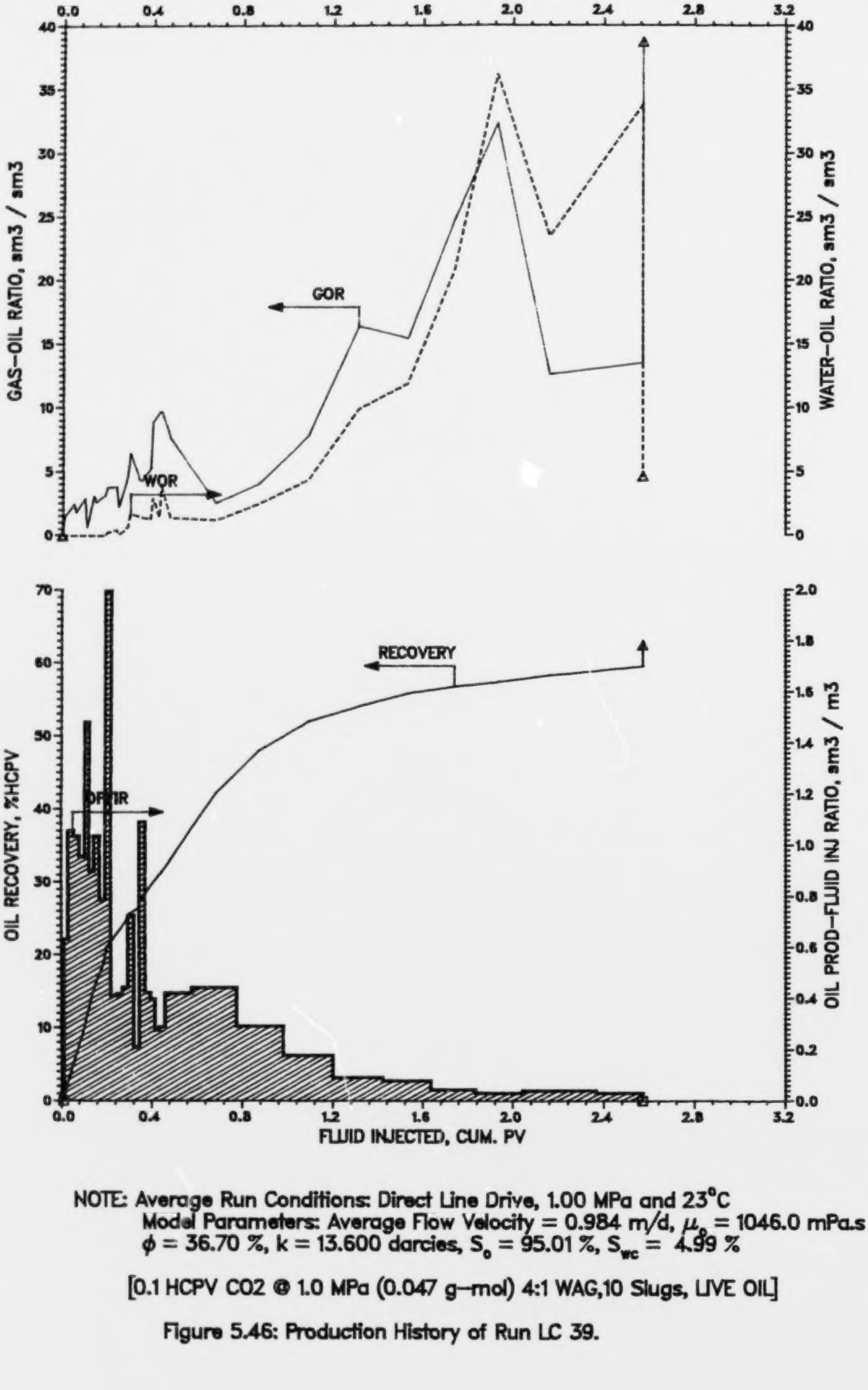
Figure 5.44: Production History of Run LC 38.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s
ϕ = 39.85 %, k = 11.800 darcies, S_o = 90.54 %, S_{wc} = 9.46 %

[0.4 HCPV CO2 @ 1.0 MPa (0.198 g–mol) 4:1 WAG,10 Slugs, LIVE OIL]

Figure 5.45: Oil Recovery Distribution of Run LC 38.



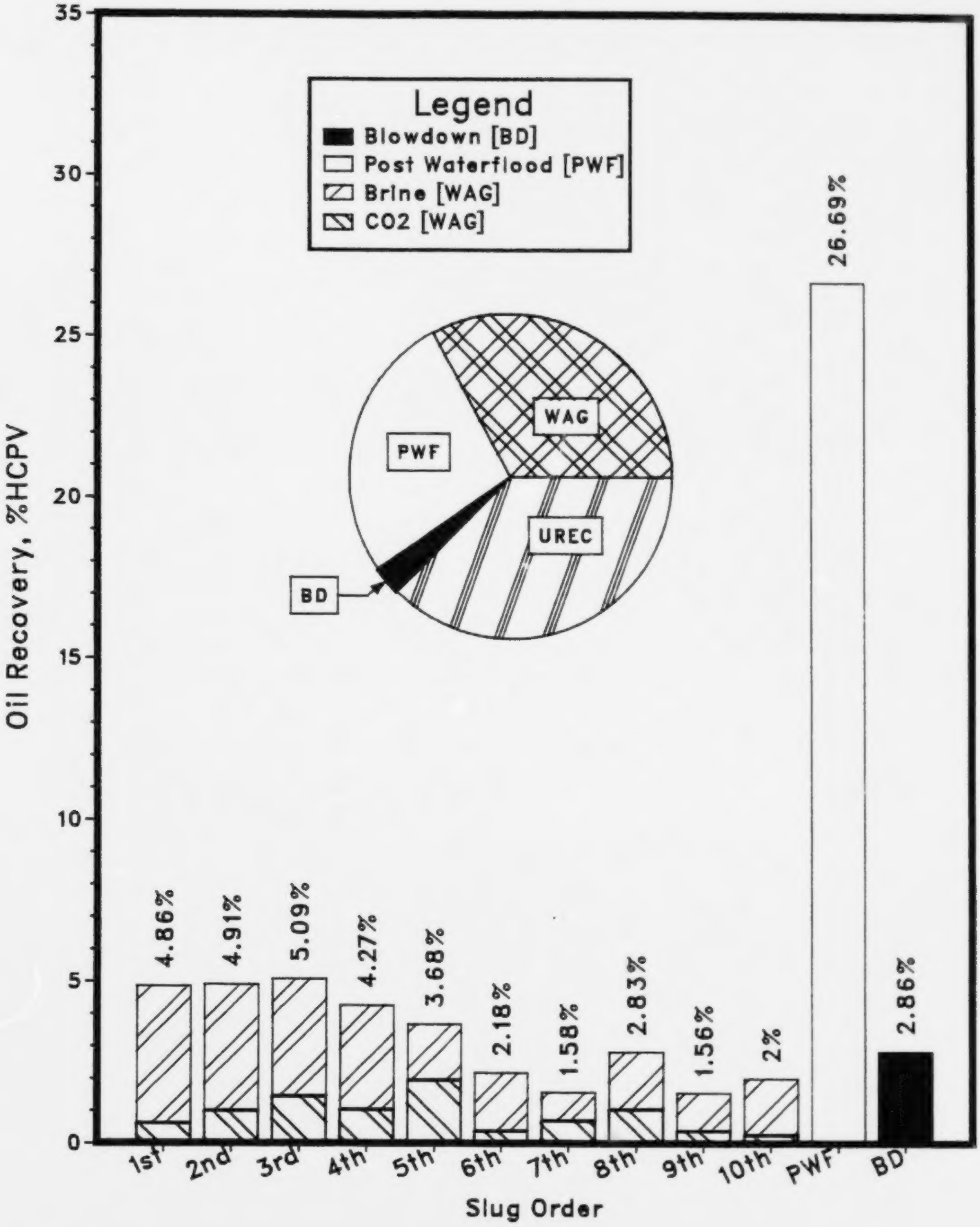
NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C

Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s

ϕ = 36.70 %, k = 13.600 darcies, S_o = 95.01 %, S_{wc} = 4.99 %

[0.1 HCPV CO2 @ 1.0 MPa (0.047 g–mol) 4:1 WAG,10 Slugs, LIVE OIL]

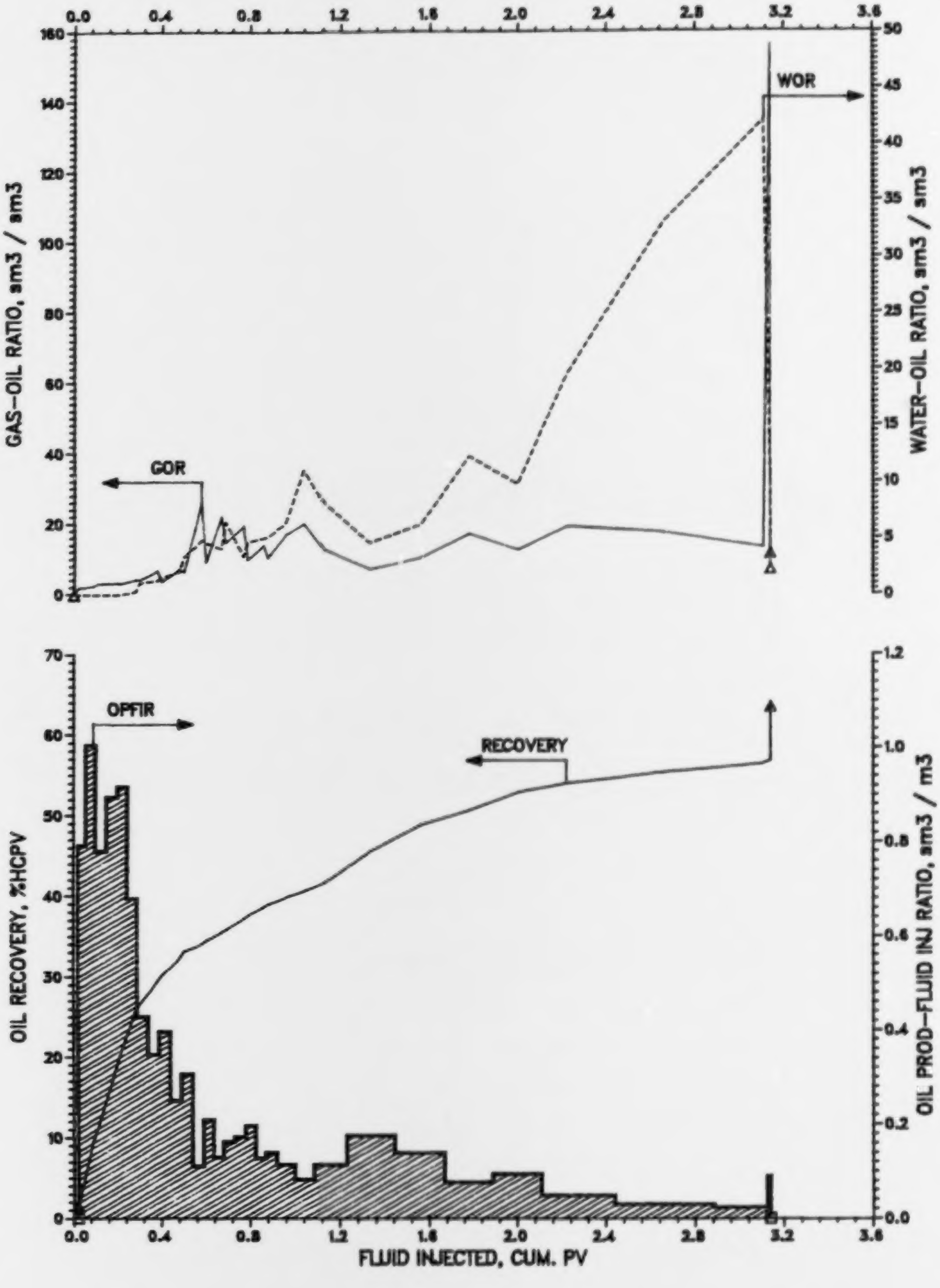
Figure 5.46: Production History of Run LC 39.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s
ϕ = 36.70 %, k = 13.600 darcies, S_o = 95.01 %, S_{wc} = 4.99 %

[0.1 HCPV CO2 @ 1.0 MPa (0.047 g-mol) 4:1 WAG,10 Slugs, LIVE OIL]

Figure 5.47: Oil Recovery Distribution of Run LC 39.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s
ϕ = 35.70 %, k = 10.200 darcies, S_o = 94.10 %, S_{wc} = 5.90 %

[0.2 HCPV CO2 @ 1.0 MPa (0.091 g-mol) 4:1 WAG,10 Slugs, LIVE OIL]

Figure 5.48: Production History of Run LC 40.

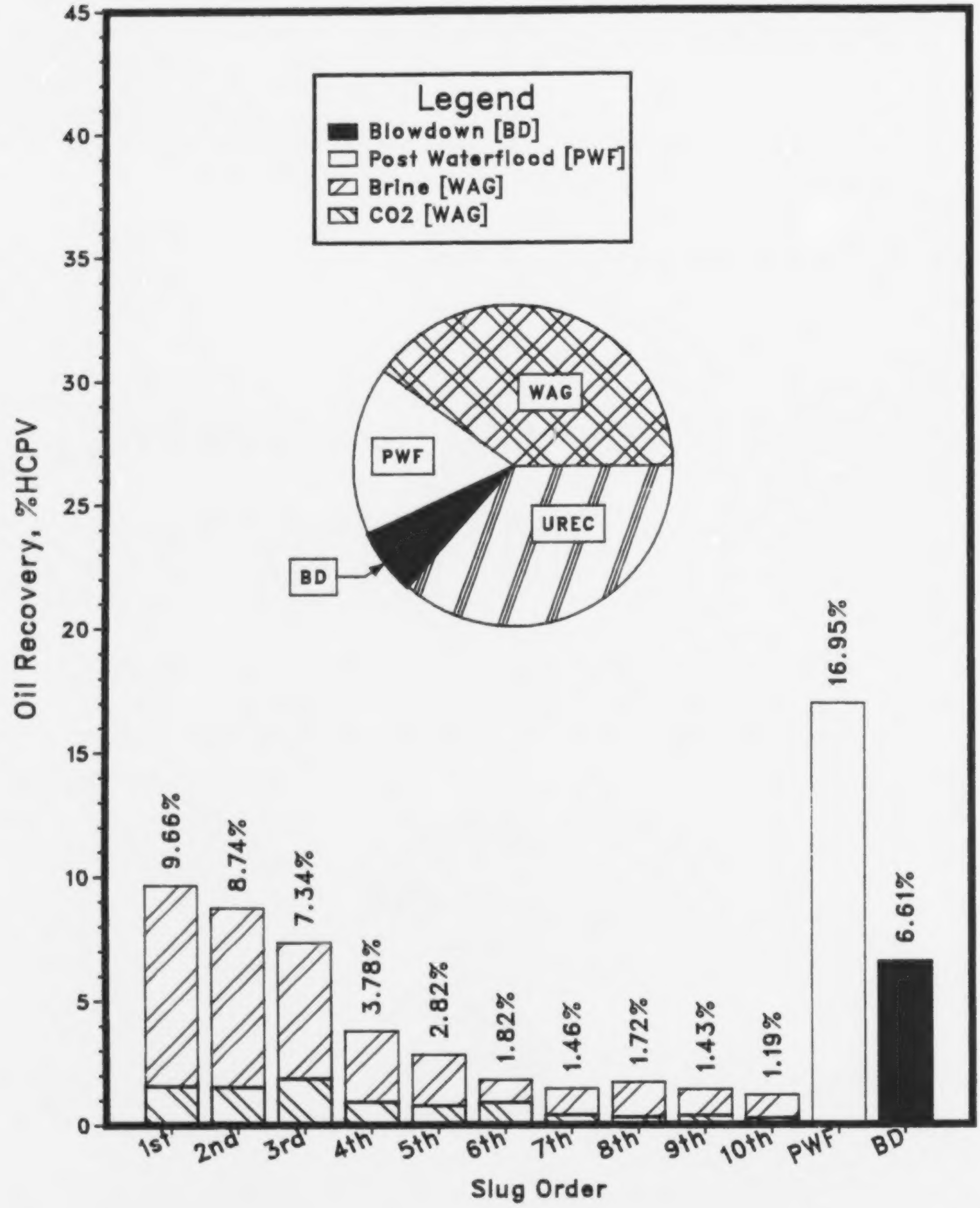
shows that a large volume of oil was produced during the early stage of the run. This is also observed in the oil recovery distribution plot (Fig. 5.49), which showed a high oil recovery at the initial stages of the run and at the waterflood and blowdown phases. The repeatability of the experiments was ascertained by carrying out the next experiment, Run LC 41, which employed the same oil and the experimental parameters (20% HCPV carbon dioxide slug, 4:1 WAG and 10 slugs). The total oil recovered from Run LC 41 (65.0%), with oil recoveries of 39.7, 18.8, and 6.5% from the WAG, waterflood, and blowdown phases respectively, was very close to that for Run LC 40 (63.6%). Figures 5.50 and 5.51 are the production history and oil recovery distribution plots for Run LC 41.

Figure 5.52 illustrates the relative contributions of the WAG, the driving waterflood and blowdown phases. From a comparison of the WAG phases of the three experiments, it is noted that Run LC 38, in which a 40% HCPV slug of carbon dioxide was injected, yielded the highest oil recovery (51.8%). Figure 5.53 shows the oil recovery versus the total fluid injected during the experiment. The curve of Run LC 38 was similar to the other two curves during the initial stages, but after about 0.5 pore volume, the three curves separated.

It is interesting that the total oil recovery in all three runs is nearly the same (Table 5.3), but the recoveries for the individual phases of the process are very different. The oil not recovered in the case of the smallest slug (10% HCPV slug of carbon dioxide, which was insufficient for an efficient recovery) was recovered by the waterflood.

Figure 5.54 shows the individual slug recoveries and shows the plot of the slug order versus the oil recovery. All three curves of Runs LC 38, LC 39, and LC 40 display a gradual increase and show the same salient trends, with the largest slug producing the maximum recovery. Each marker on the curve indicates the cumulative recovery obtained at each stage of the process. Figure 5.55 shows the same recovery values in the form of a bar graph.

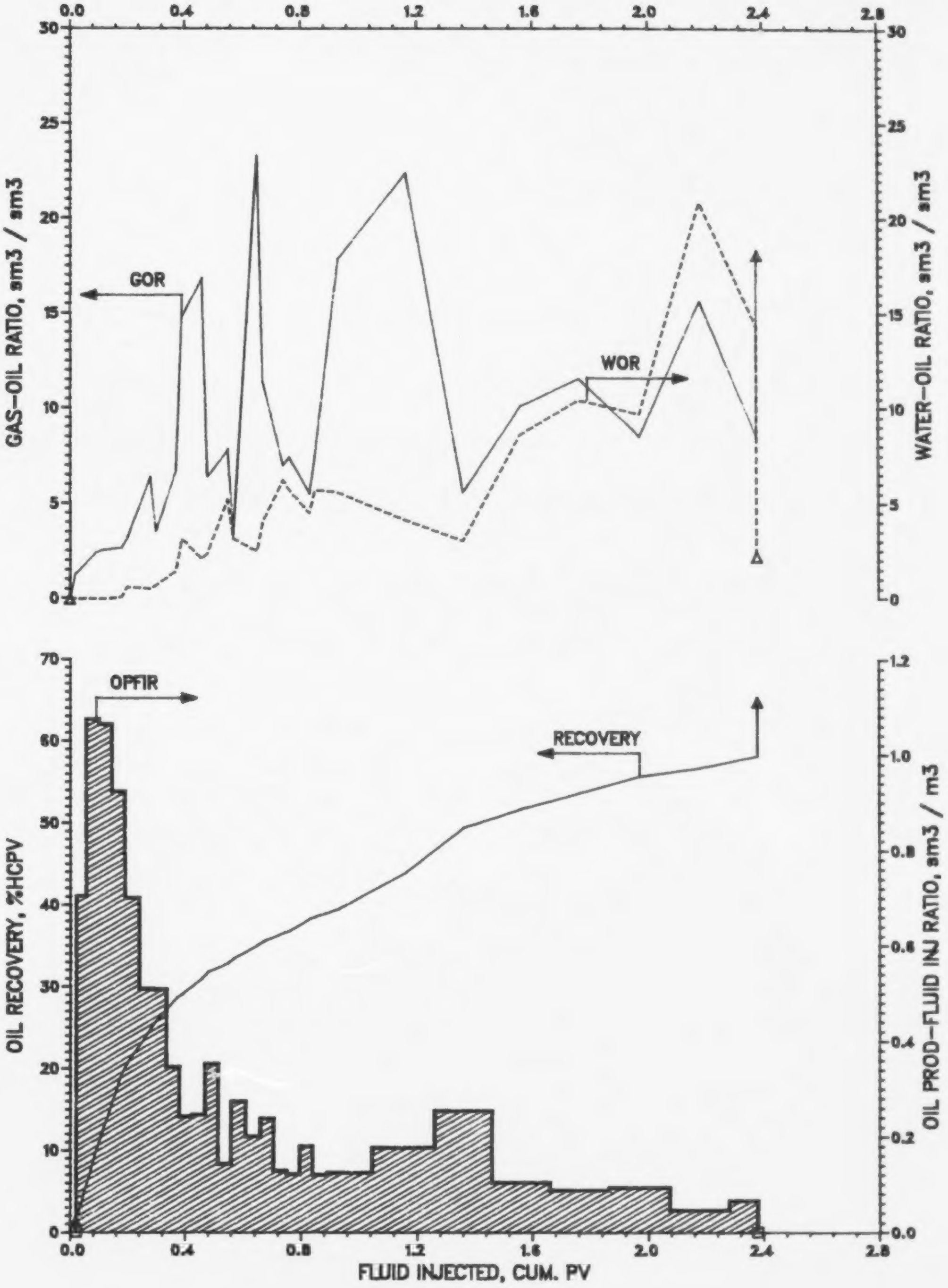
An important point to note from the live oil experiments, when compared to the dead oil experiments, is that in the blowdown phase, a larger volume of gas was produced. This could be attributed to the gases, both carbon dioxide and methane being released from solution when the pressure in the core was reduced to room pressure. Also, these figures appear to indicate that the longest flood life, which in this case is taken as the duration of the run, produces the maximum recovery.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s
ϕ = 35.70 %, k = 10.200 darcies, S_o = 94.10 %, S_{wc} = 5.90 %

[0.2 HCPV CO2 @ 1.0 MPa (0.091 g–mol) 4:1 WAG,10 Slugs, LIVE OIL]

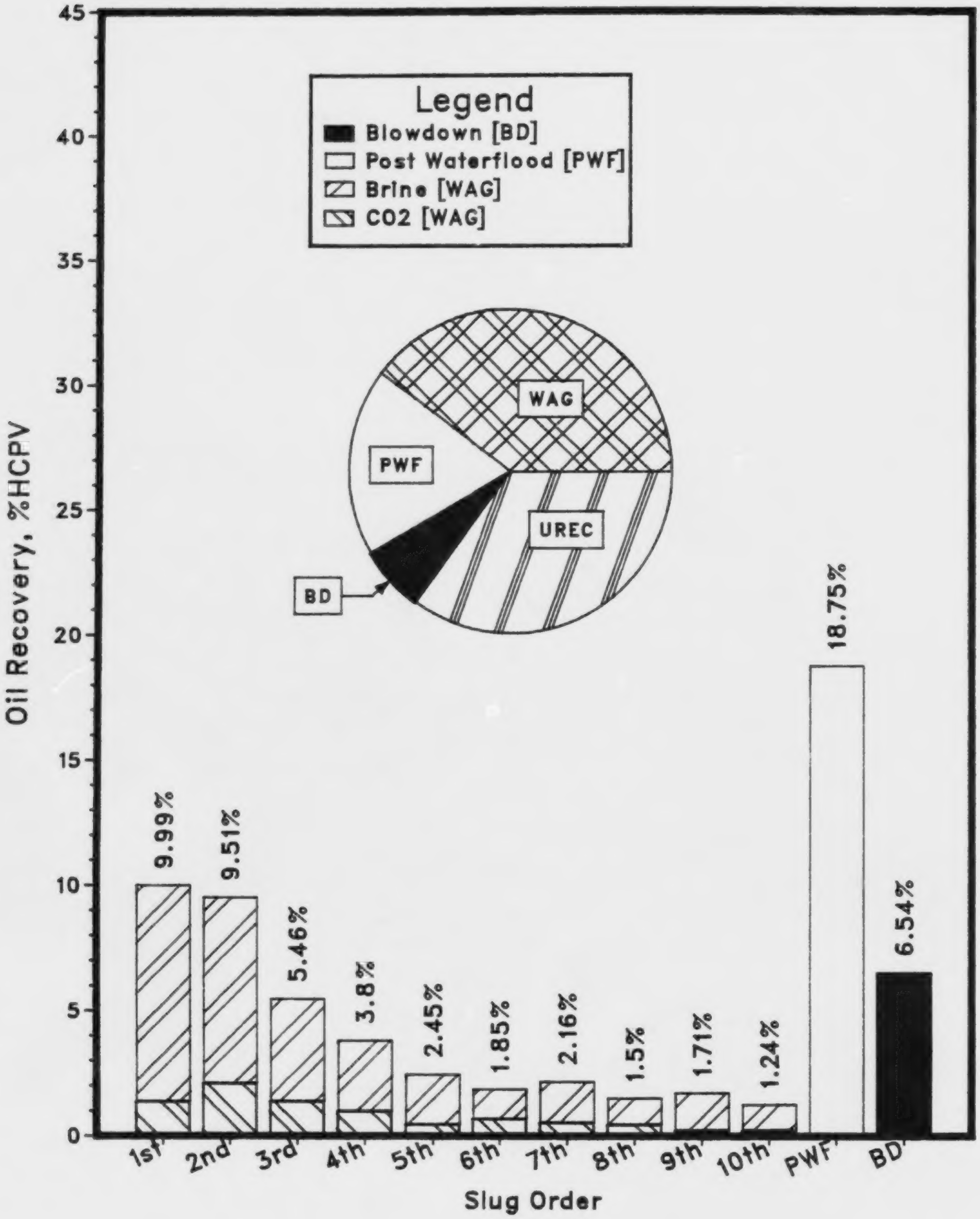
Figure 5.49: Oil Recovery Distribution of Run LC 40.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s
ϕ = 38.92 %, k = 14.150 darcies, S_o = 92.30 %, S_{wc} = 7.70 %

[0.2 HCPV CO2 @ 1.0 MPa (0.091 g–mol) 4:1 WAG,10 Slugs, LIVE OIL]

Figure 5.50: Production History of Run LC 41.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s
ϕ = 38.92 %, k = 14.150 darcies, S_o = 92.30 %, S_{wc} = 7.70 %

[0.2 HCPV CO2 @ 1.0 MPa (0.091 g-mol) 4:1 WAG,10 Slugs, LIVE OIL]

Figure 5.51: Oil Recovery Distribution of Run LC 41.

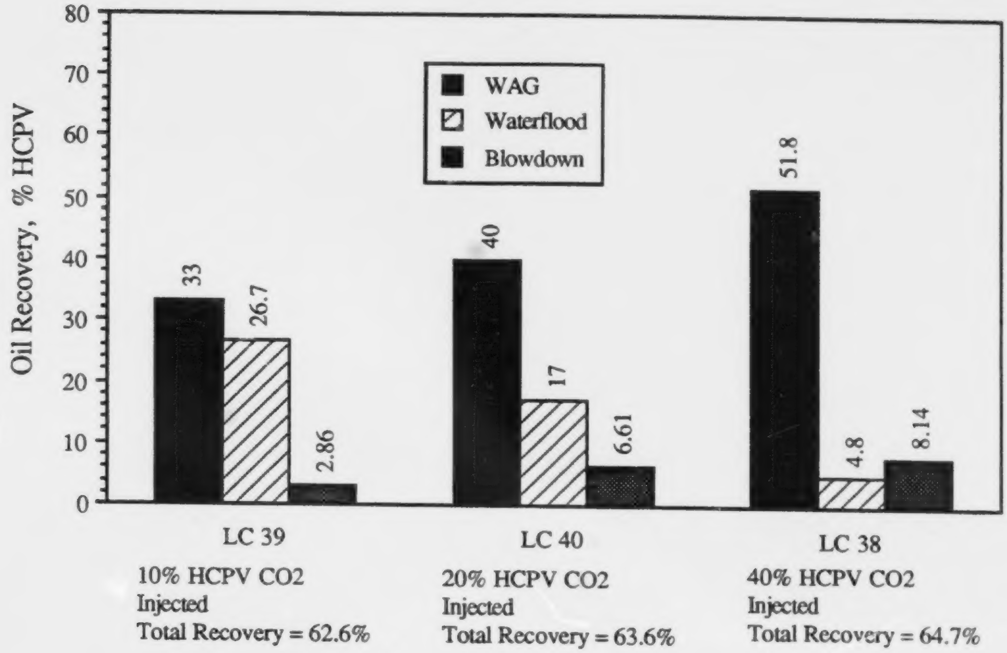


Figure 5.52: Linear Model Experiments Using Live Oil
@ 1.0 MPa, 4:1 WAG and 10 Slugs.

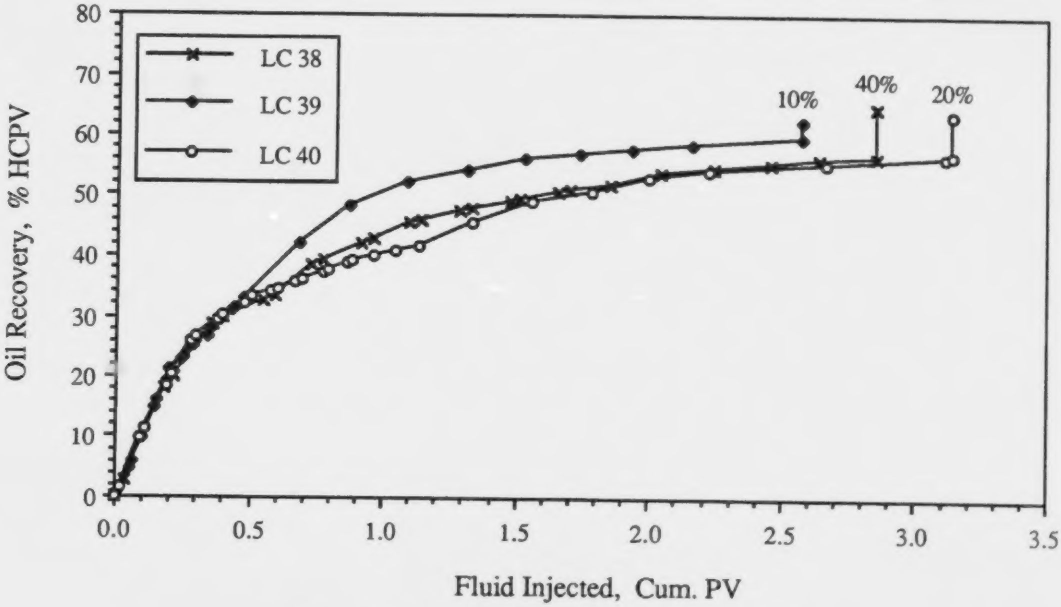


Figure 5.53: Linear Model Experiments Using Live Oil
@ 1.0 MPa, 4:1 WAG and 10 Slugs.

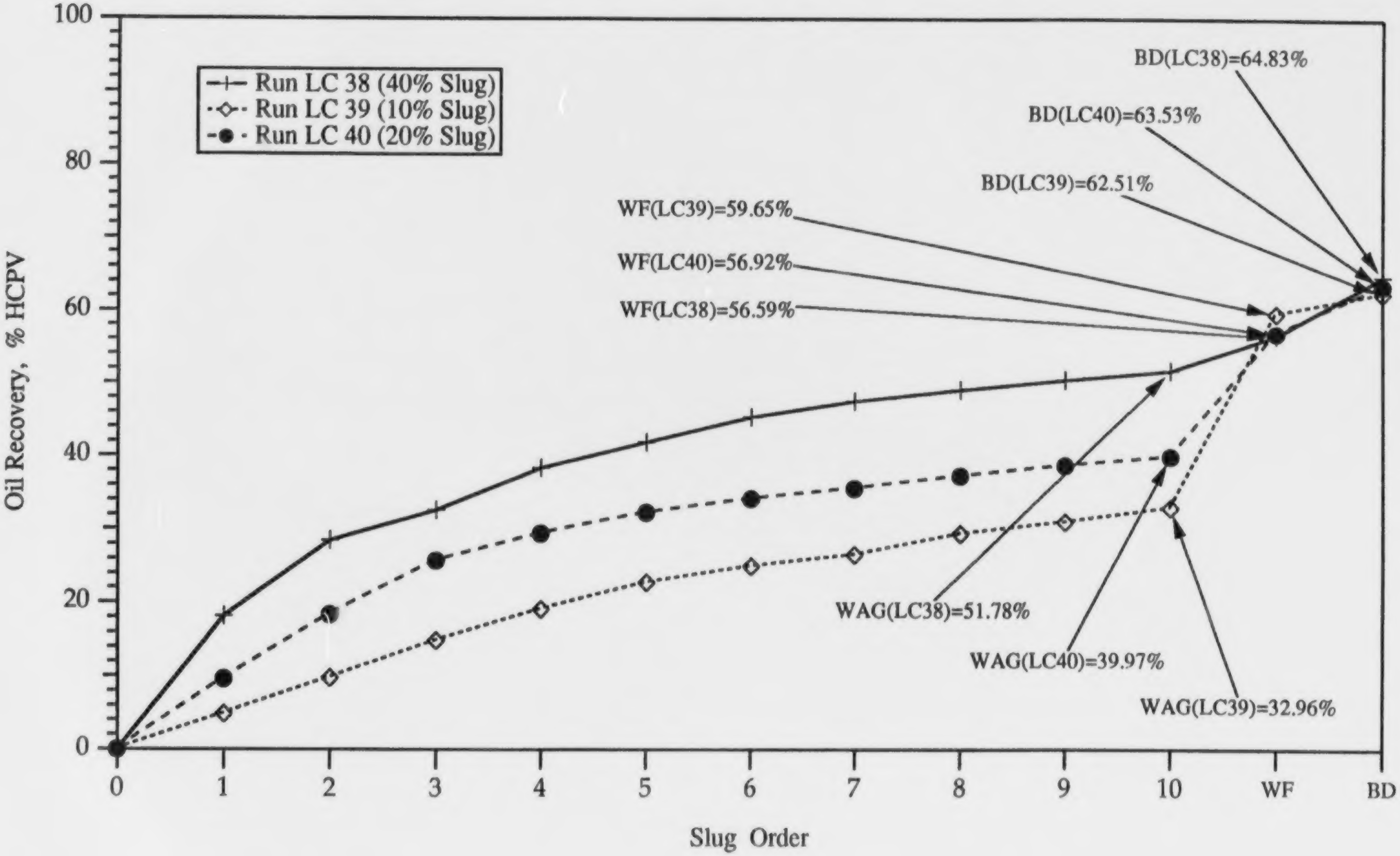


Figure 5.54: Live Oil Run Comparisons for Different Slug Sizes.

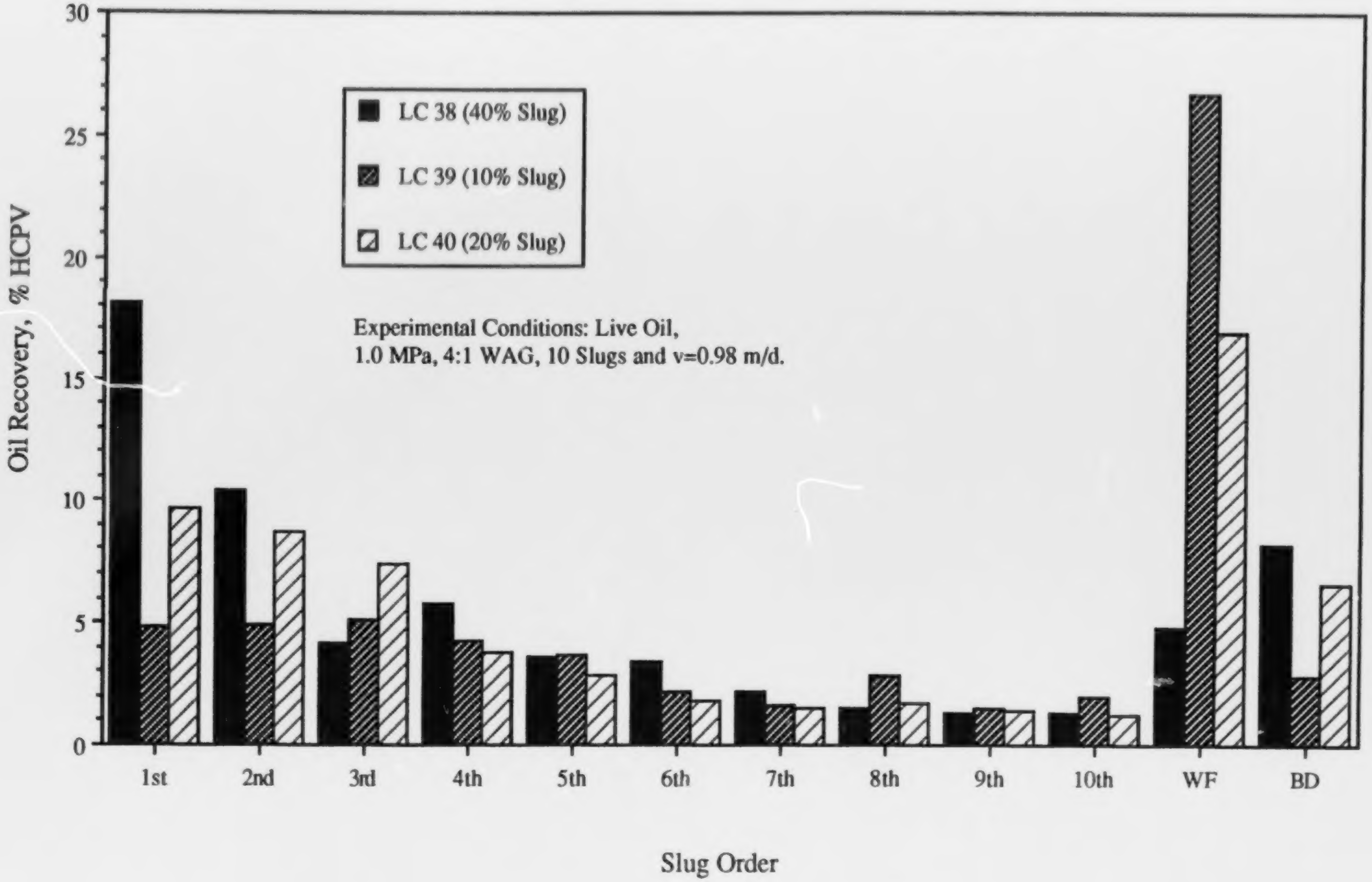


Figure 5.55: Live Oil Run Comparisons for Different Slug Sizes.

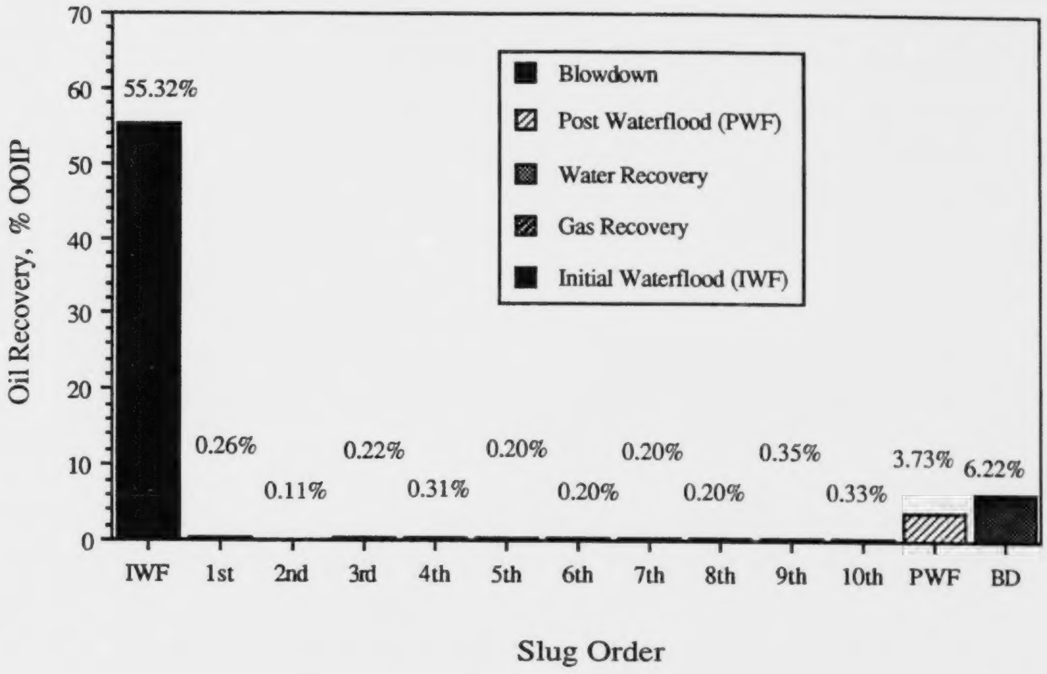
5.2.3.1 Tertiary Recovery Experiment Using Live Oil

In tertiary floods, as mentioned before, the porous medium is first waterflooded and then the immiscible carbon dioxide WAG process is employed followed by the post waterflood and blowdown phases. As seen from Table 5.3, the oil recovery value from the initial waterflood (Run LC 43) using live oil is approximately 55.3% and the incremental recovery varies from 10 to 12.5% at 1.0 MPa. This value is higher than the oil recovery value (41.5%) obtained from the waterflood experiment (Run LC 34) conducted at 2.5 MPa, using a dead oil sample which had an oil viscosity of 882 mPa.s. Figure 5.56 depicts the oil recovery distribution for Run LC 43 and shows the oil recovery obtained individually from the initial waterflood, the following WAG phase and the post waterflood and blowdown phases, respectively. From this experiment, it is possible to infer that the WAG process is able to recover additional oil in the tertiary mode. The residual oil is taken as the basis for oil recovery calculation and the WAG process is employed, followed by the waterflood and blowdown phases and the resulting values are tabulated under LC 44 (Table 5.3).

Figure 5.57 is the production history plot of the tertiary run. The gas-oil ratio curve shows that the gas breakthrough occurred right at the beginning, and the curve shows that carbon dioxide was not used efficiently. The water breakthrough occurred much later than that of gas. The OPFIR curve shows that an oil bank was formed after water breakthrough, with a high oil production rate. The second oil bank was formed at the start of the WAG process, with an increasing gas-oil ratio. The carbon dioxide evidently caused swelling of the residual oil, resulting in an increase in oil saturation. Thus, in the blowdown phase, more residual oil was produced than in the WAG or waterflood phases.

5.2.3.2 Comparison of Live Oil and Dead Oil Experiments Using Identical Parameters

An experiment was conducted to compare the results from two experiments using identical parameters except that the oil samples were different. The live oil sample had a calculated viscosity of 784 mPa.s, while the dead oil sample had a viscosity of 1046 mPa.s. Figure 5.58 shows a comparison of the production histories of the gas-oil ratio and water-oil ratio curves for the two experiments. From an analysis of the production history curves, it is observed that the duration of the live oil experiment was longer and that more gas than water was produced during the experiment. This is attributed to methane dissolved in the



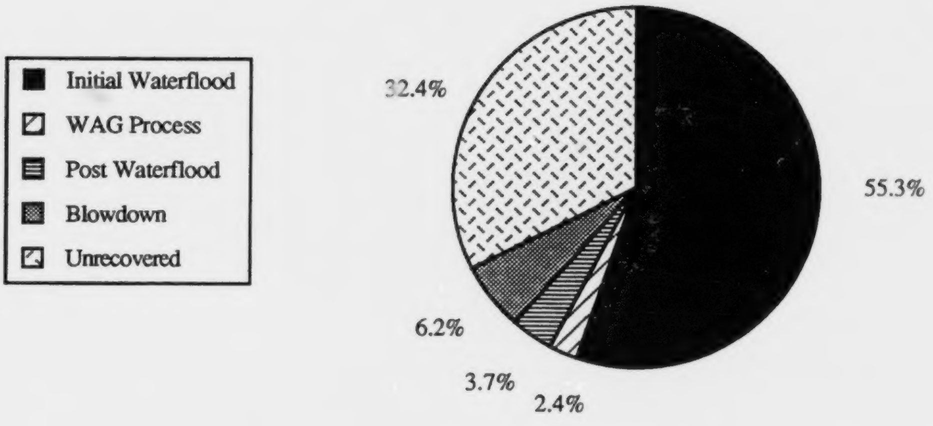
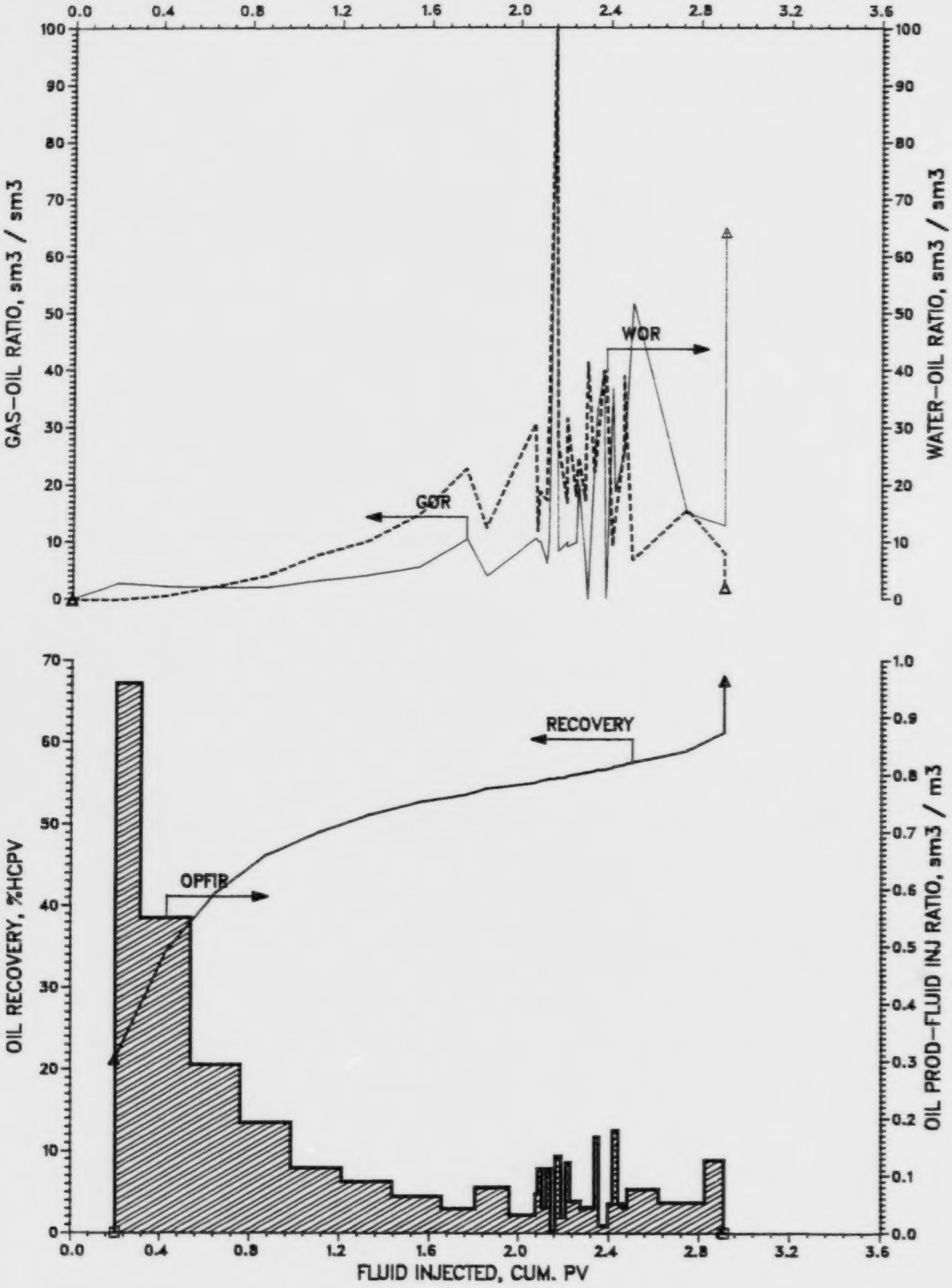


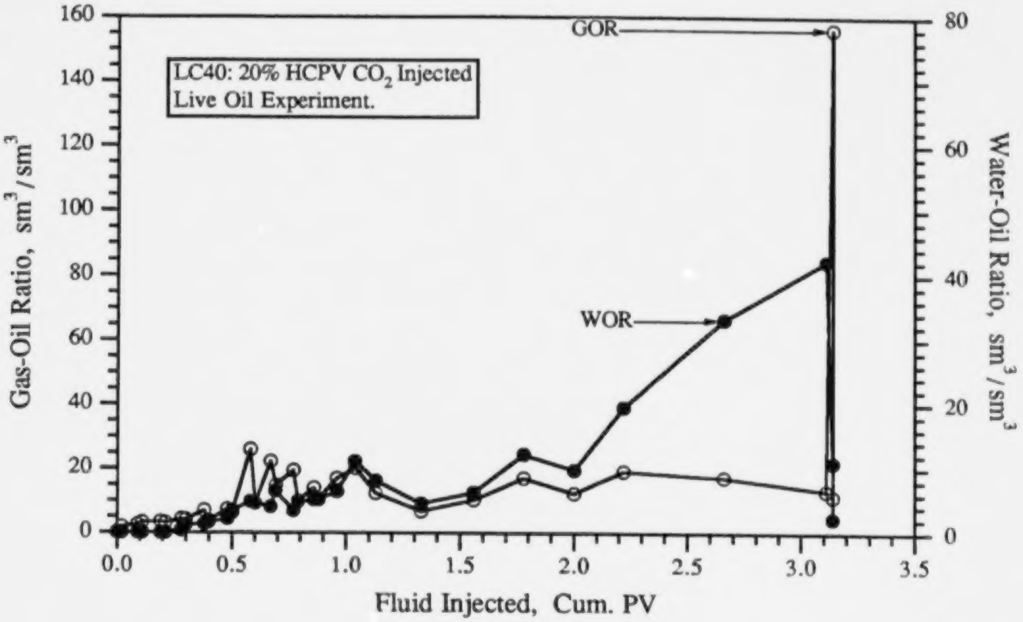
Figure 5.56: Tertiary Oil Recovery Distribution (Runs LC 43 & LC 44).

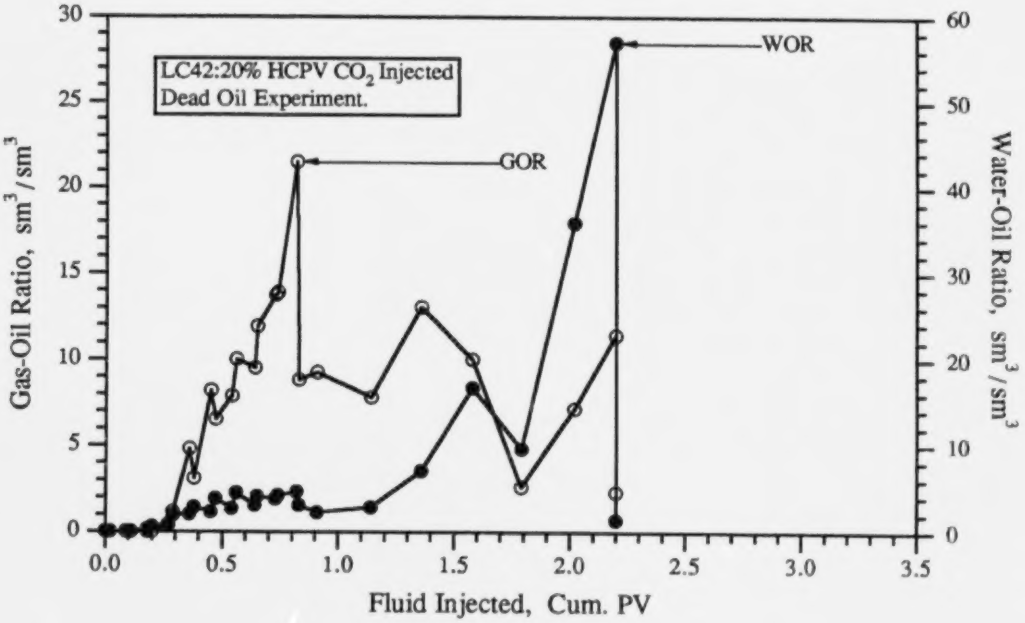


NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s
ϕ = 35.12 %, k = 10.450 darcies, S_o = 92.03 %, S_{wc} = 7.97 %

[2.26 WF => 0.2 RHPV CO2 @ 1.0 MPa (0.039 g-mol) 4:1 WAG, 10 Slugs]

Figure 5.57: Production History of Run LC 43.





Experimental Parameters:
1.0 MPa, 4:1 WAG, 0.98 m/d, and 10 Slugs.

Figure 5.58: Comparison of Production Histories of the GOR and WOR for a Live Oil and Dead Oil Sample Using Identical Parameters.

oil. It is possible that carbon dioxide displaced the methane and the released gas helped drive the oil to the production wells. Also, it is observed that at the end of the live oil experiment, a large volume of gas was produced while at the end of the dead oil experiment, only a small volume of gas was produced resulting in a lower oil recovery in the blowdown phase.

Figure 5.59 shows a plot of the cumulative fluid injected versus the oil recovery, and the slug order versus the oil recovery. It shows that from the beginning of the experiment, the oil recovery was higher for the live oil experiment and this can be attributed possibly to the increased drive due to the presence of methane. Figure 5.60 is the oil recovery distribution plot for Run LC 42 and Fig. D4 is the detailed production history plot of Run LC 42.

5.2.3.3 Repeatability of Experiments

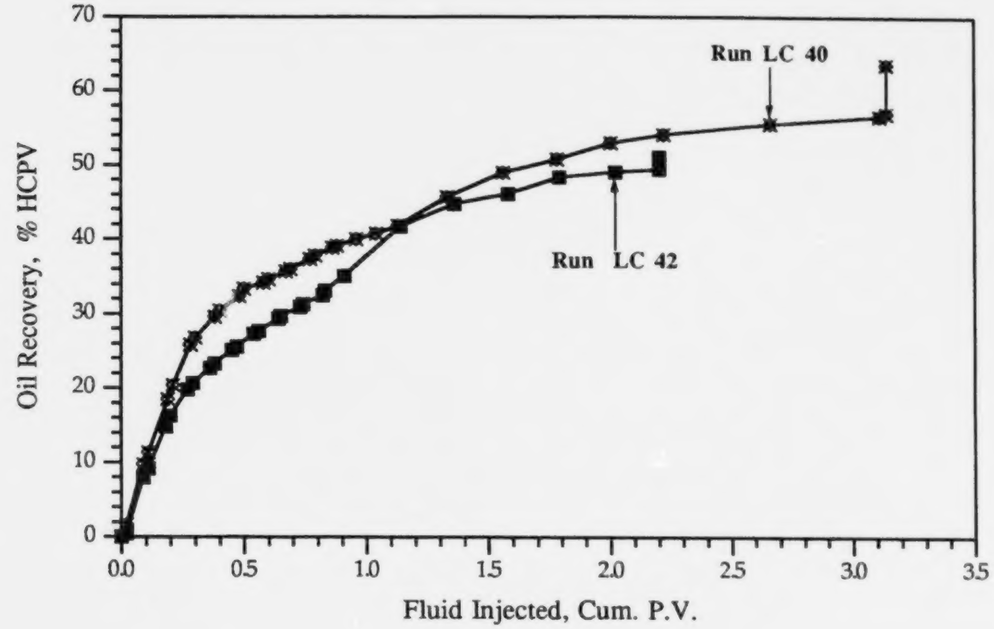
It is essential to conduct a few experiments and inspect the results to note if a consistent set of results is obtained. Three live oil experiments, Run LC 37, LC 40, and LC 41 utilized a 20% HCPV slug of carbon dioxide, at 1.0 MPa, 4:1 WAG ratio, and 10 alternating slugs of carbon dioxide and water. The total oil recoveries were 66.4, 63.5, and 65.0%, respectively, showing good agreement and reproducibility of the runs.

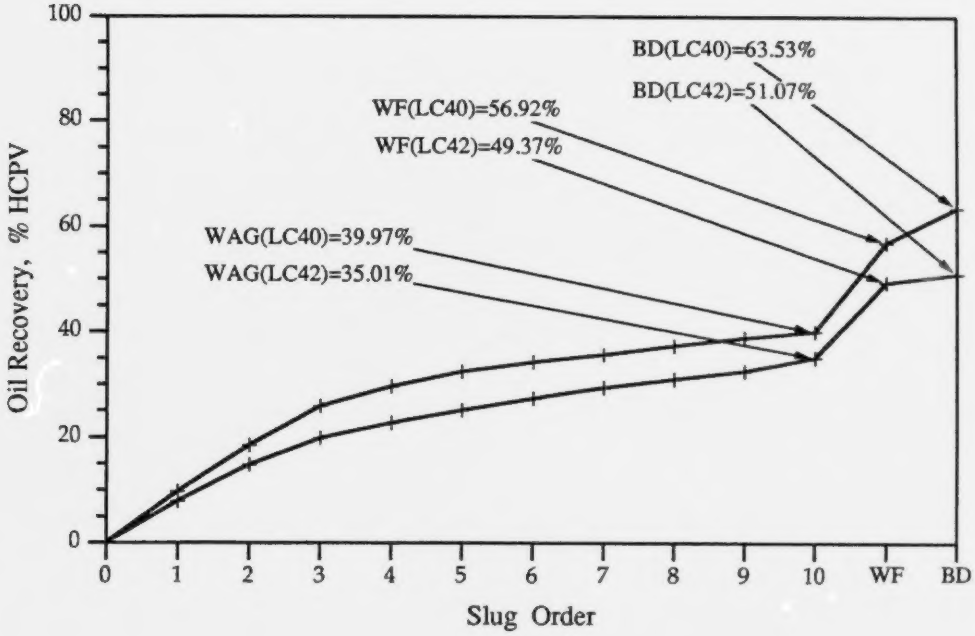
Figure 5.61 shows the GOR and WOR production histories for the live oil experiments having the same slug size, and Fig. 5.62 shows a plot of the fluid injected versus the oil recovery and the slug order versus the oil recovery. It was observed that all the runs were quite similar and followed virtually a similar pattern. Figure 5.63 illustrates the oil recovery of the various phases of the three experiments giving their respective values.

5.2.4 Effect of Slug Size on the WAG and Total Oil Recoveries.

Figures 5.64 and 5.65 show total oil recovery and WAG recovery as functions of slug size. The dotted lines indicate the runs conducted at 1.0 MPa while the plain lines represent the runs carried out at 2.5 MPa.

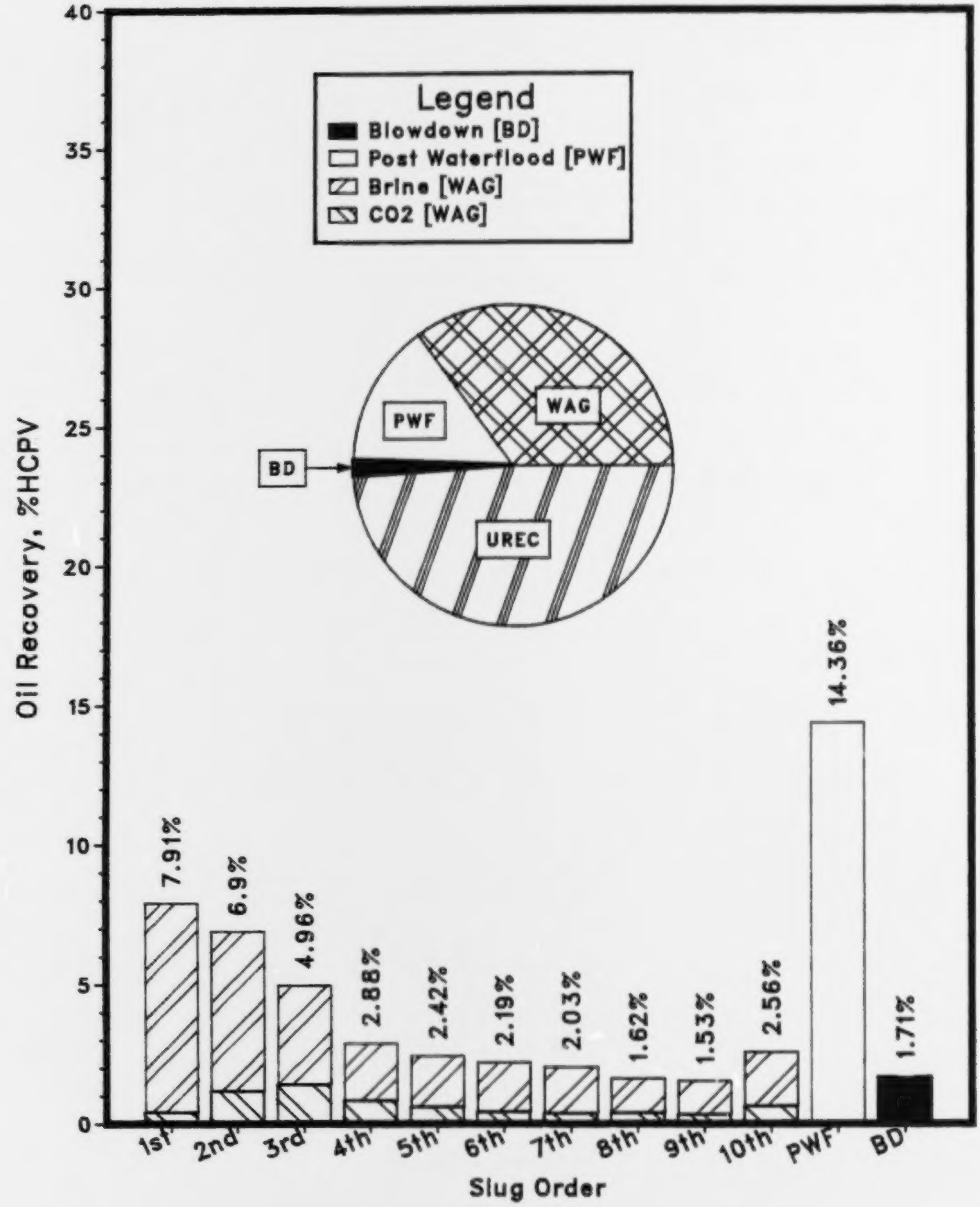
The curves show that the slug sizes were between 20 and 40% HCPV in runs yielding the higher oil recoveries. The curve corresponding to the runs conducted in the two-





Experimental Parameters:
1.0 MPa, 4:1 WAG, and 10 Slugs.
Viscosity : Live-oil = 784 mPa.s, Dead-oil = 1046 mPa.s

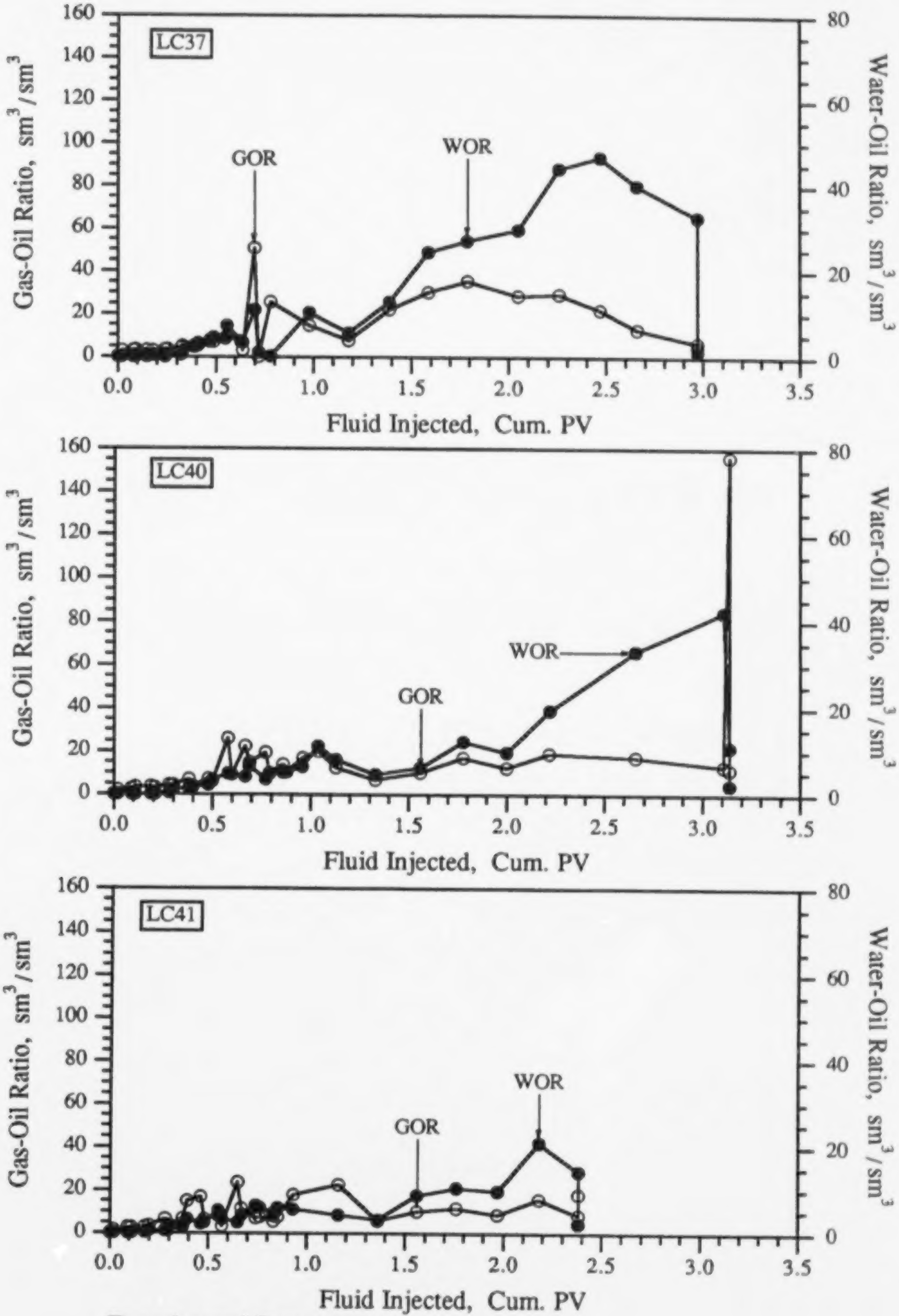
Figure 5.59: Oil Recovery Results of a Live Oil and Dead Oil Sample using a 20% HCPV Carbon Dioxide Slug.
(Linear Model Experiment).



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s
ϕ = 36.10 %, k = 10.990 darcies, S_o = 90.22 %, S_{wc} = 9.78 %

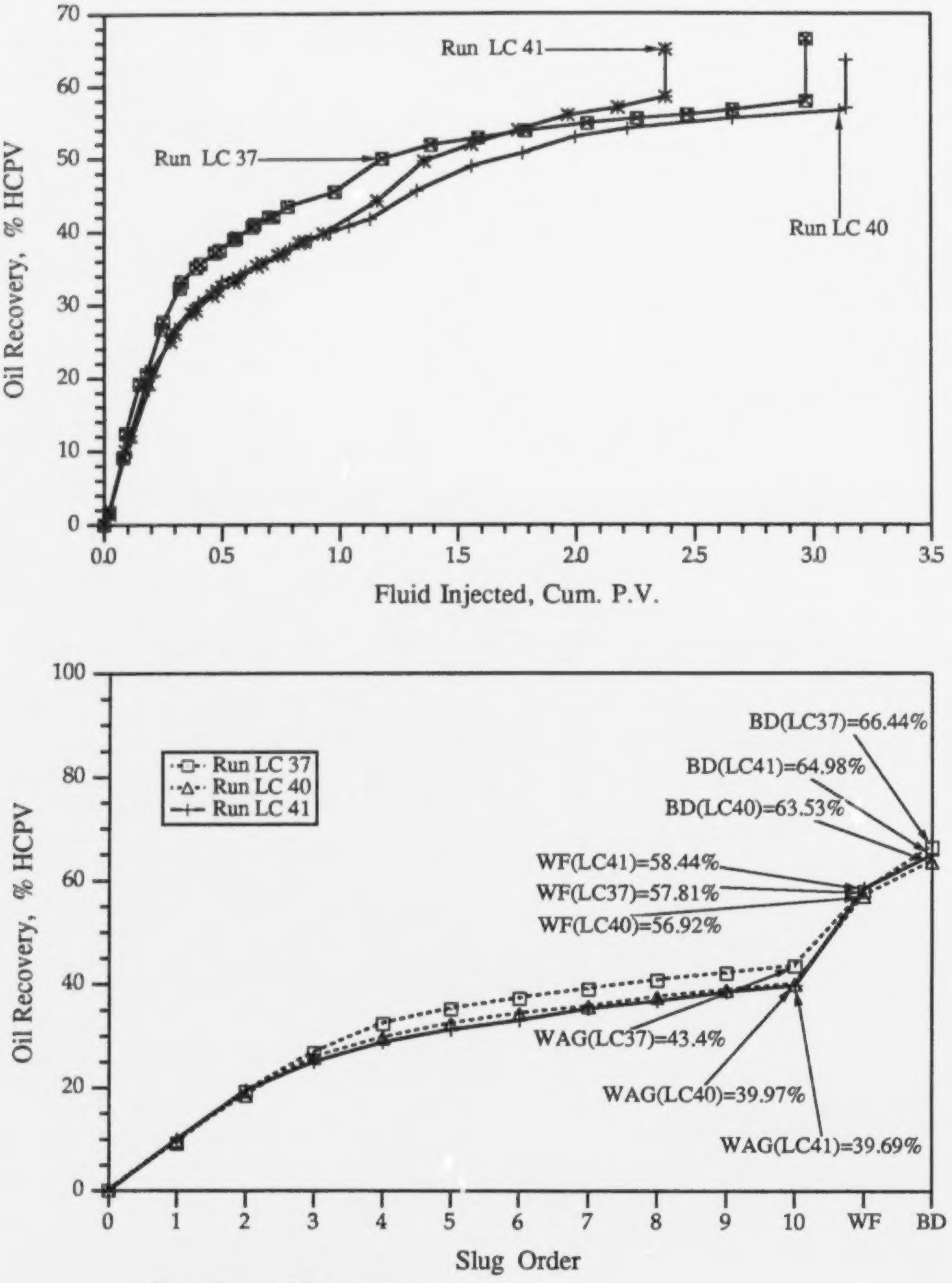
[0.2 HCPV CO2 @ 1.0 MPa (0.089 g-mol) 4:1 WAG,10 Slugs]

Figure 5.60: Oil Recovery Distribution of Run LC 42.



Experimental Parameters
Live Oil, 1.0 MPa, 4:1 WAG and 10 Slugs.

Figure 5.61: GOR and WOR Production History of the Live Oil Experiments for a Same Slug Size.
(Linear Model Experiments).



Experimental Parameters:
Live Oil, 1.0 MPa,4:1 WAG, and 10 Slugs.

Figure 5.62: Live Oil Run Comparison for a 20% HCPV
Carbon Dioxide Slug.
(Linear Model Experiment).

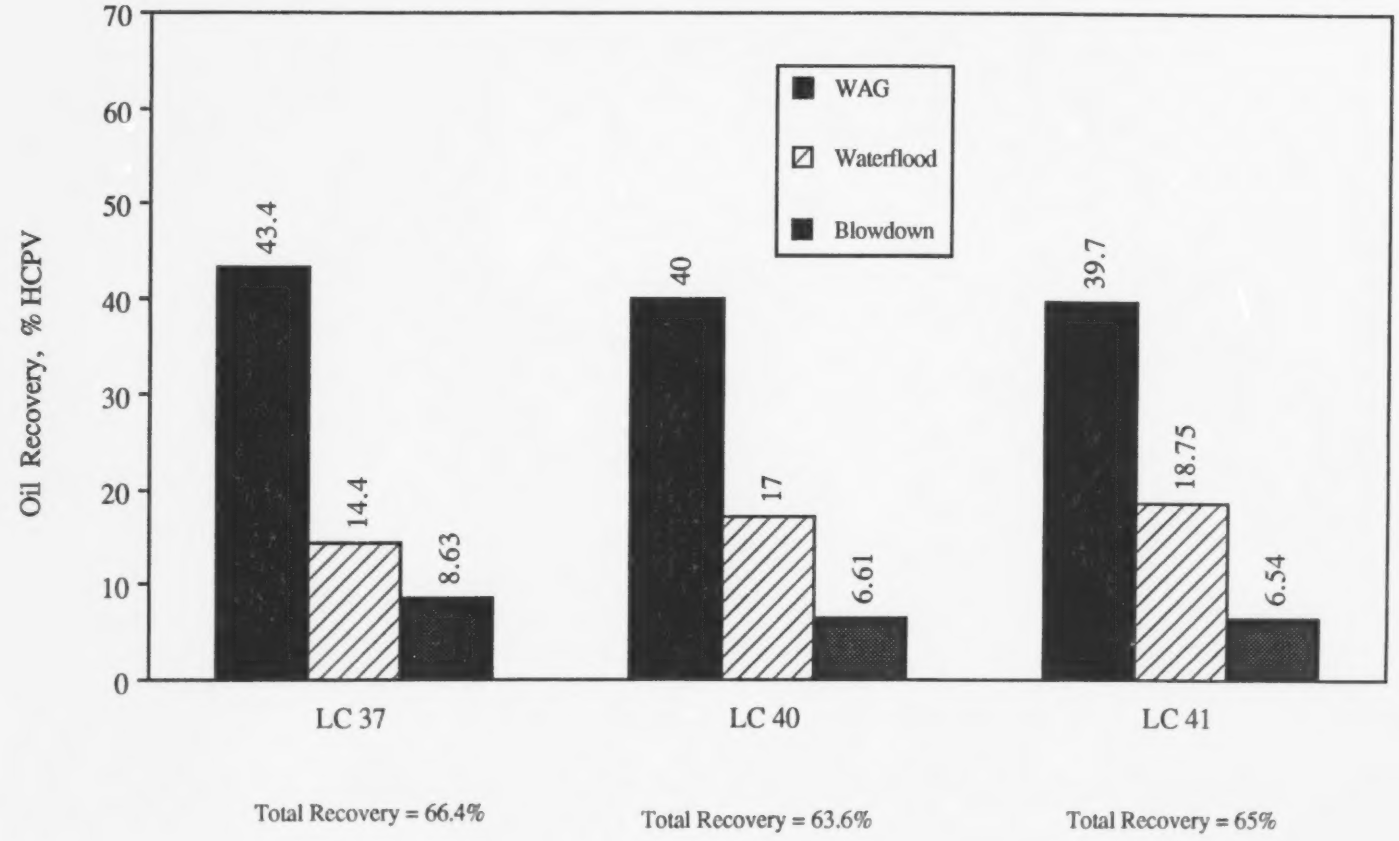


Figure 5.63: Reproducibility of Live Oil Experiments using
a 20% HCPV Carbon Dioxide, 4:1 WAG Ratio, 10 Slugs and v=0.98 m/d.

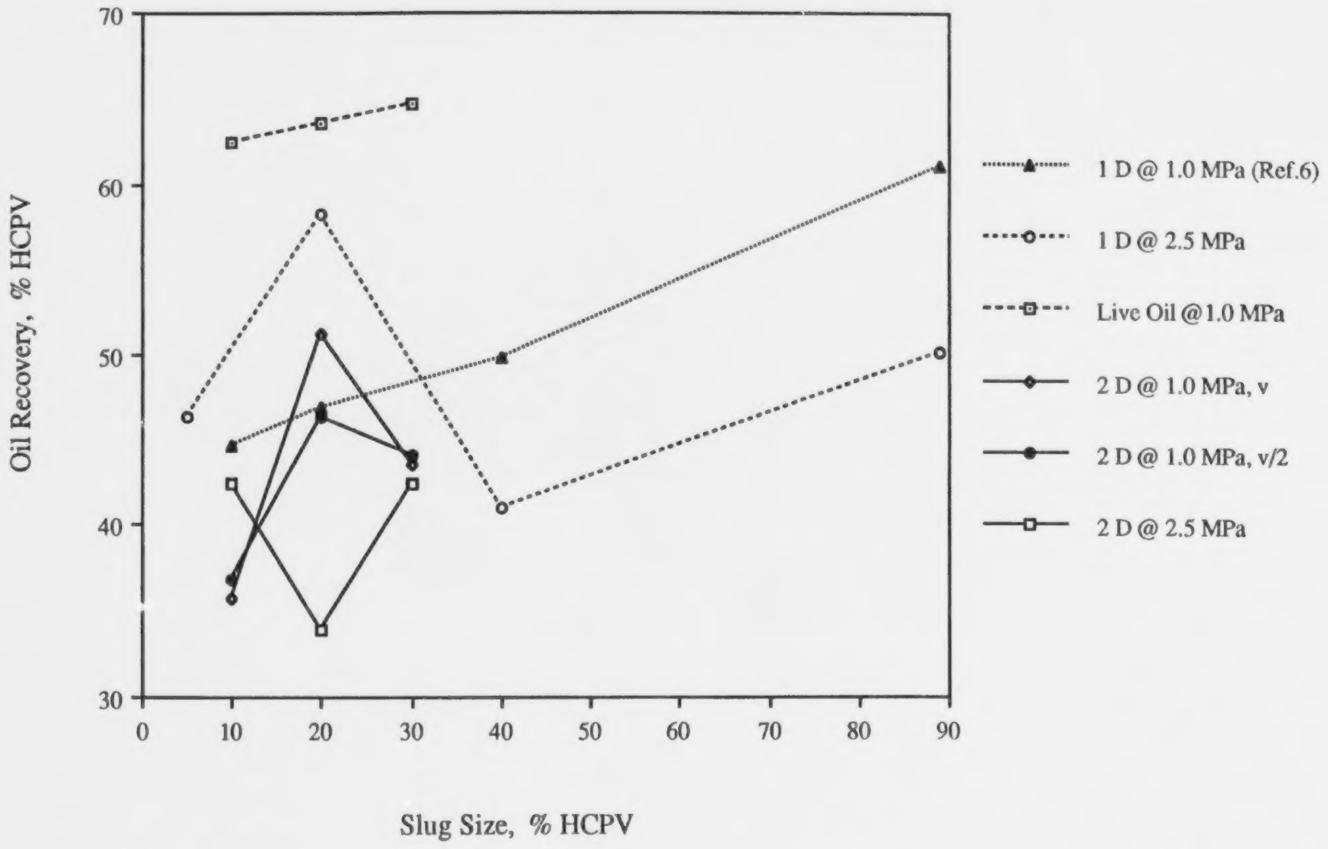


Figure 5.64: Effect of Slug Size on Total Oil Recovery.

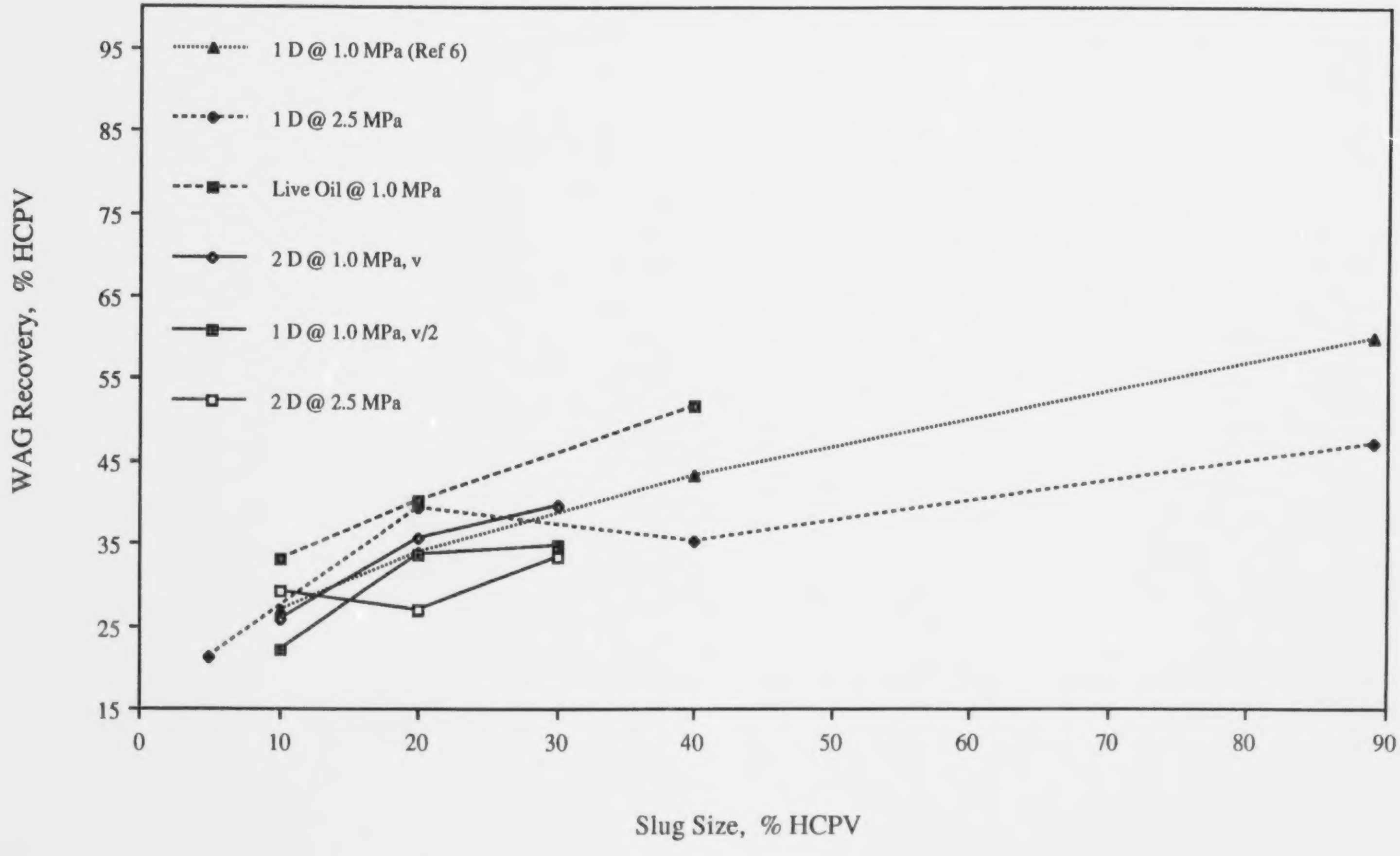


Figure 5.65: Effect of Slug Size on WAG Recovery.

dimensional model at 2.5 MPa show that the recovery for the experiment (Run GTD 2) using a 20% HCPV carbon dioxide slug was less than (33.9%) because this run was conducted at 1.6m/d, while the flow velocity in the other two runs was 2.6 m/d.

Figure 5.65 shows a more consistent trend of WAG recovery with slug size

5.2.5 Effect of Blowdown on Oil Recovery

As mentioned in the literature review, the blowdown phase of the immiscible carbon dioxide WAG process is important to the overall oil recovery. Figure 5.66 presents a comparison of various blowdown recoveries for the two-dimensional model. The recoveries are shown by the different slug sizes and the operating pressure. Figure 5.67 presents the results of the linear model experiments and Fig. 5.68 presents the results of the live oil experiments conducted.

The trend seems to be that the larger the slug injected, the higher is the blowdown recovery. In most cases, the magnitude of the blowdown recovery is small when compared to the total oil recovery, but blowdown recovery is a significant part of the total oil recovery in the live oil experiments. During the secondary recovery in the blowdown phase, pressure is lowered and the gas dissolved in the residual oil evolves, effectively mobilizing the trapped oil. In general, the blowdown recovery increases with pressure as more gas dissolves in oil at higher pressures and thus, when the pressure is lowered, more gas is released (Fig. 5.66).

5.2.6 Effect of Pressure on Carbon Dioxide Retention and Requirement

Figure 5.69 shows that carbon dioxide requirements increase with pressure, partly because the carbon dioxide volume will be lower at the higher pressure. Carbon dioxide retention also increased with an increase in pressure, in view of the higher solubility.

Both figures imply that at higher pressures, carbon dioxide retention and requirement increase. This increase could be attributed to the fact that at higher pressures, there will be increased solubility. The large carbon dioxide retention values at the higher pressure show that large volumes of gas were retained in the model.

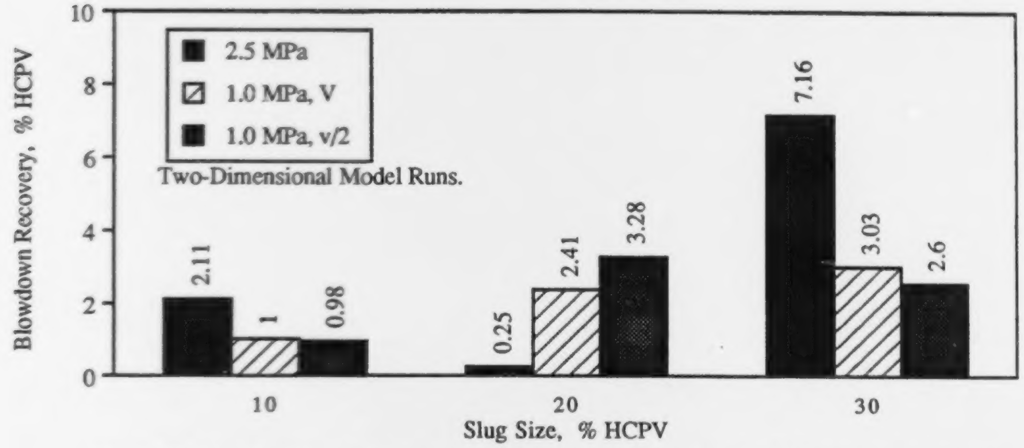


Figure 5.66: Blowdown Recovery for the Two-Dimensional Model Experiments.

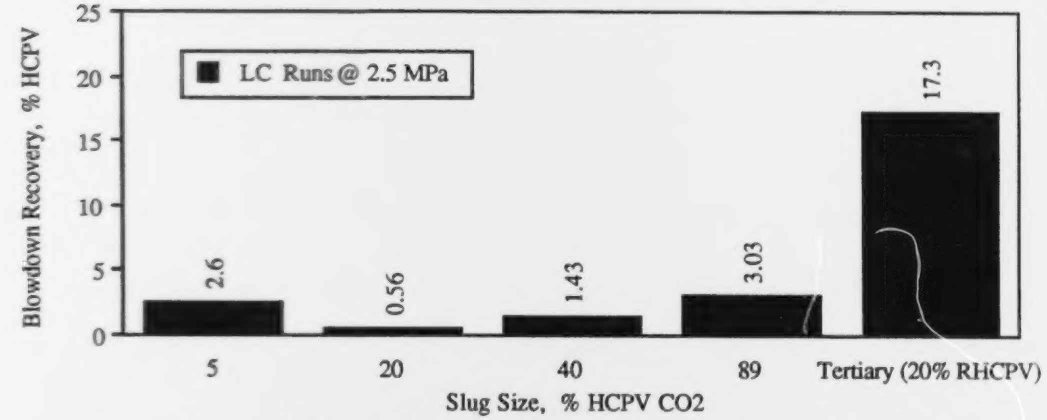


Figure 5.67: Blowdown Recovery for the Linear Model Experiments.

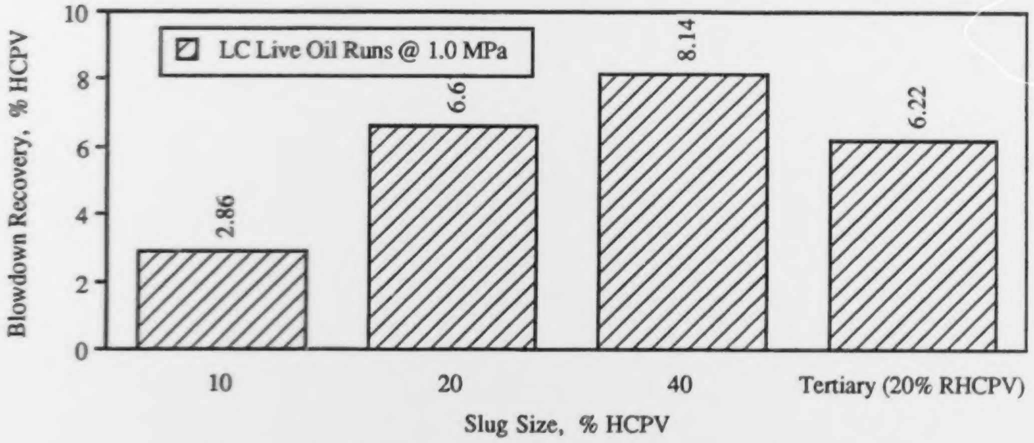


Figure 5.68: Blowdown Recovery for the Live Oil Experiments.

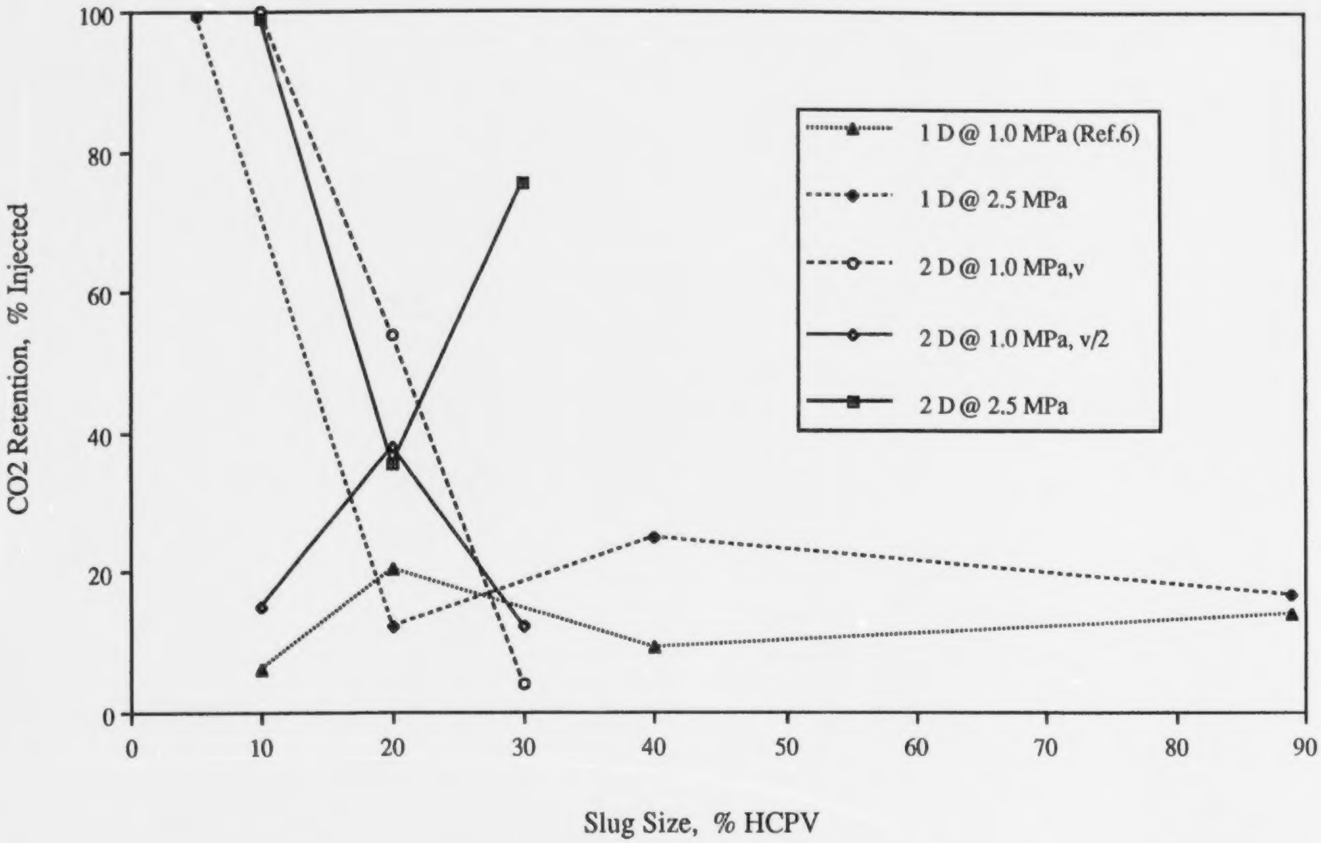


Figure 5.69: Effect of Pressure on CO2 Retention.

5.3 Comparison of the Present Experimental Results with the Previous Work

The previous studies conducted by Rojas[3], Zhu[5], and Dyer[6] are summarized in Chapter 3. Several experiments were conducted to verify the repeatability and additional experiments were formulated to study the process.

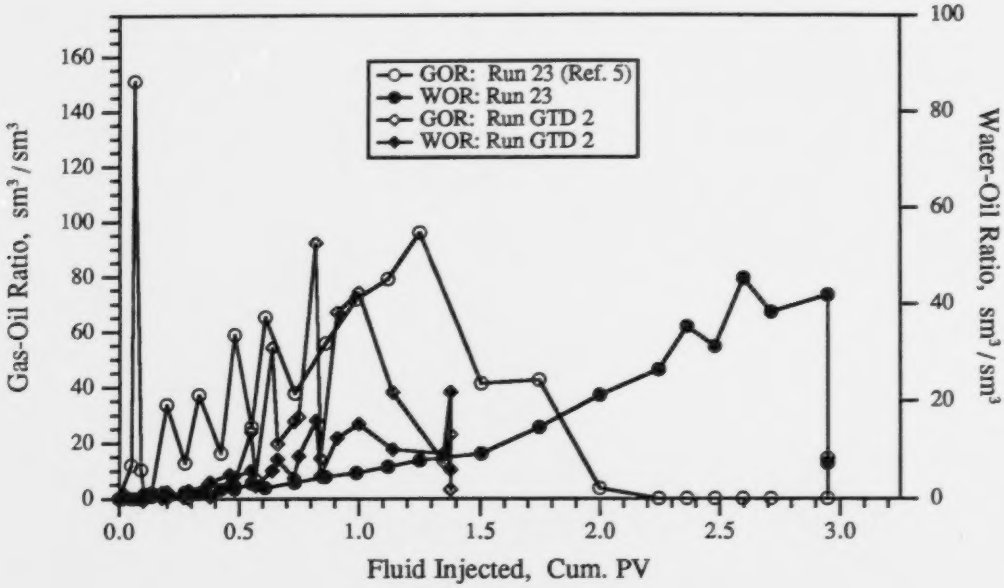
5.3.1 Experiment Conducted at 2.5 MPa in the Two-Dimensional Model

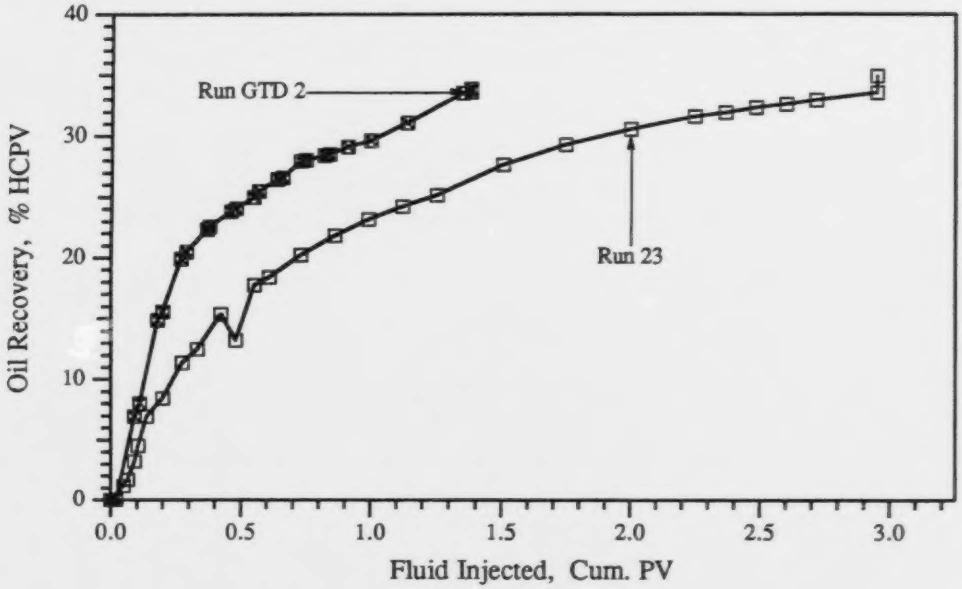
Zhu[5] conducted the majority of his experiments at 5.5 MPa using carbon dioxide and nitrogen. Only two experiments were conducted at 2.5 MPa, one experiment utilizing nine alternating slugs and a brine velocity of 1.29 m/d, and a the second experiment (Run 23) using ten slugs at 1.55 m/d.

An experiment, Run GTD 2, was conducted using the same parameters as Run 23, i.e. a 4:1 WAG ratio, ten slugs and a brine flow velocity of 1.55 m/d to estimate the recovery values. The duration of this experiment was shorter when compared to Run 23. Figure 5.70 presents the production history and oil recovery distribution of both these experiments. As illustrated by the gas-oil ratio curve, early gas breakthrough occurred in Run 23 which would have possibly caused some channelling to occur. After the initial surge, the fluctuations resembled the injection of gas in the WAG process and gradually reduced towards the end of the experiment. The gas-oil ratio for Run GTD 2 was moderate at the start of the experiment and had only a few high peaks. Overall, carbon dioxide gas seemed to be more efficiently utilized in Run GTD 2 as the carbon dioxide requirement for Run 23 was 55.8 sm^3/sm^3, while for Run GTD 2 it was only 16.3 sm^3/sm^3. As a water-oil ratio of 20:1 was reached, the waterflooding process for Run GTD 2 was terminated, while for Run 23, the waterflood process was extended. But the overall recovery was similar for both experiments, as the total oil recovery was 34.9% in Run 23 and 33.9% in Run GTD 2. The oil production rate in Run GTD 2 was higher than in Run 23, as shown by the slopes of the respective recovery curves (Fig. 5.70).

5.3.2 Experiments Conducted at 1.0 and 2.5 MPa in the Linear Model

Dyer[6] initially conducted a group of experiments at 1.0 MPa in the linear model using carbon dioxide slug sizes of 10, 20, 40 and 89% HCPV. A similar set of experiments was conducted using 5, 20, 40, and 89% HCPV slugs of carbon dioxide, with identical





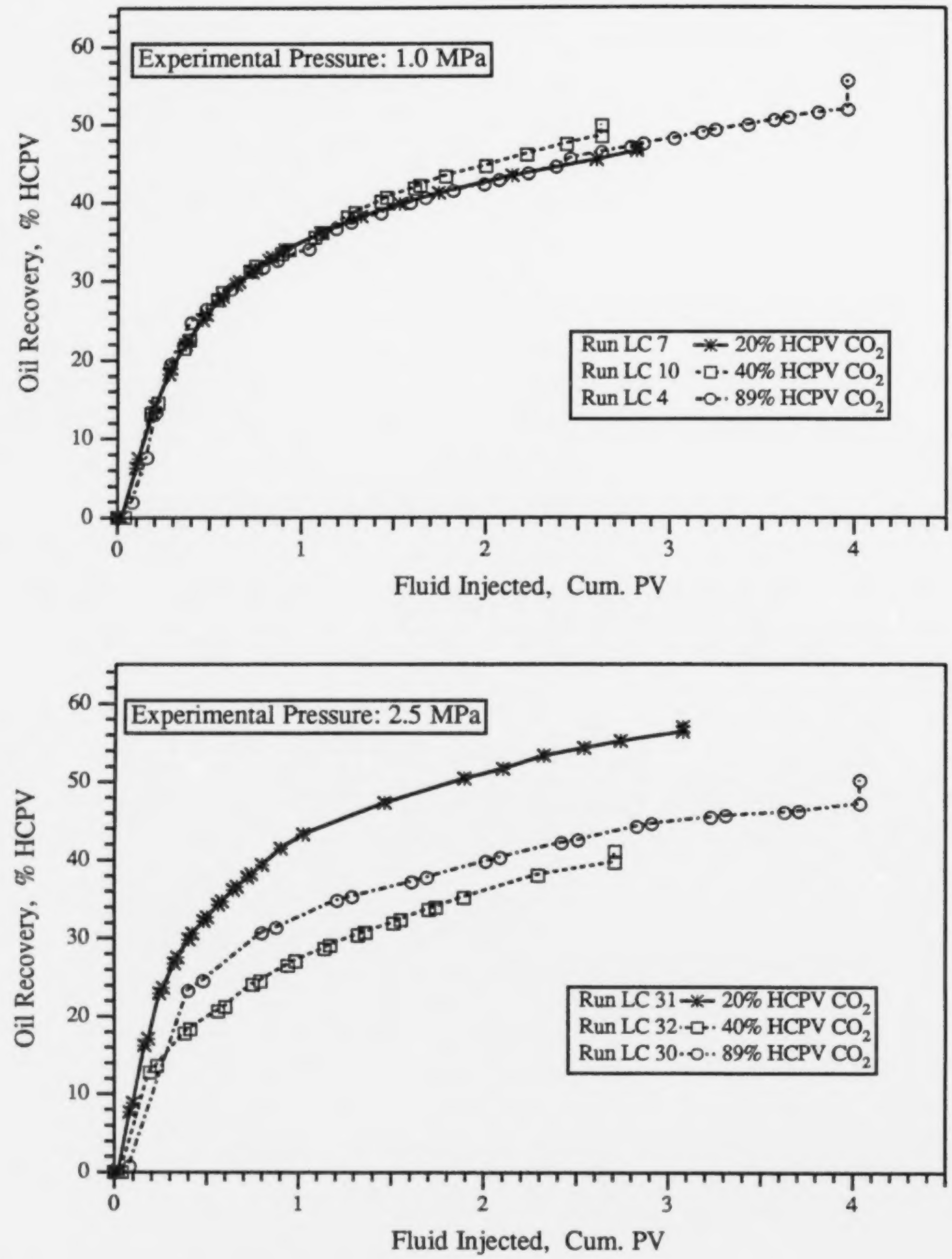
Run Parameters:
2.5 MPa, 4:1 WAG, 1.55 m/d Brine Flow Velocity and 10 Slugs.

Figure 5.70: Production History and Oil Recovery Distribution of Run GTD 2 and Run 23. (Ref.5)
Two-Dimensional Model Experiments.

parameters to the experiments conducted by Dyer except that the operating pressure was at 2.5 MPa. Figure 5.71 shows a comparison of the oil recovery history for the 20, 40, and 89% slug sizes only. It is observed that for the experiments conducted at 1.0 MPa, the recovery curves are quite similar, with Run LC 4 (89% HCPV slug of carbon dioxide) yielding a maximum oil recovery of 55.5%. The results for the runs conducted at 2.5 MPa show a greater dependence on carbon dioxide slug size.

Observation of the production histories of these experiments, in Figs. 5.72 and 5.73, shows that the gas-oil ratios for the 2.5 MPa experiments were higher than the gas-oil ratios for the experiments conducted at 1.0 MPa. At the higher pressure, the moles of gas injected was larger and thus produced a larger volume of gas in the experiment. During Run LC 31 (20% HCPV slug of carbon dioxide), the gas-oil ratio (Fig. 5.72) was moderate in the initial phase of the experiment. At about one pore volume, there was a large increase in gas mobility. After that, the gas-oil ratio steadily declined, while the water-oil ratio increased. This can also be inferred from the oil production history curve in Fig. 5.71 indicating that the oil recovery increased until about one pore volume and later declined. This probably was caused by the formation of a small path or channel that resulted in the injected fluid not being in contact with the rest of the porous medium. A similar trend was noticed for Run LC 7 in Fig. 5.72 where the volume of gas steadily increased, but at 0.75 PV the increase in the gas-oil ratio was greater. More water was produced in the experiment and this was indicated by the increase in the water-oil ratio curve and the volume of gas produced decreased.

Figure 5.73 displays the gas-oil ratio and water-oil ratio curves for the 40 and 89% slug size experiments. It is evident that more gas was produced in the experiments carried out at 2.5 MPa, and that it can be attributed to larger moles of gas used at the higher pressure as explained above. The gas-oil ratio curve for Run LC 32 shows oscillations, which appear to indicate that the gas was not utilized efficiently. Figures 5.74 and 5.75 show the oil recovery distribution for each phase of the experiment. Run LC 32 has the least recovery of 41.1% among the three experiments in that group, while Runs LC 31 and LC 30 had total oil recoveries of 57.0 and 50.2%, respectively. As the slug size increased, the total oil recovery also increased, as shown by Fig. 5.74. This trend was not consistent in the higher pressure (2.5 MPa) experiments as seen from Fig. 5.75.



Experimental Parameters:
4:1 WAG Ratio, 0.984 Brine Flow Velocity and 10 Slugs.

Figure 5.71: A Comparison of the Effect of Carbon Dioxide Slug Size on Oil Recovery at 1.0 (Ref.6) and 2.5 MPa.
Linear Model Experiments.

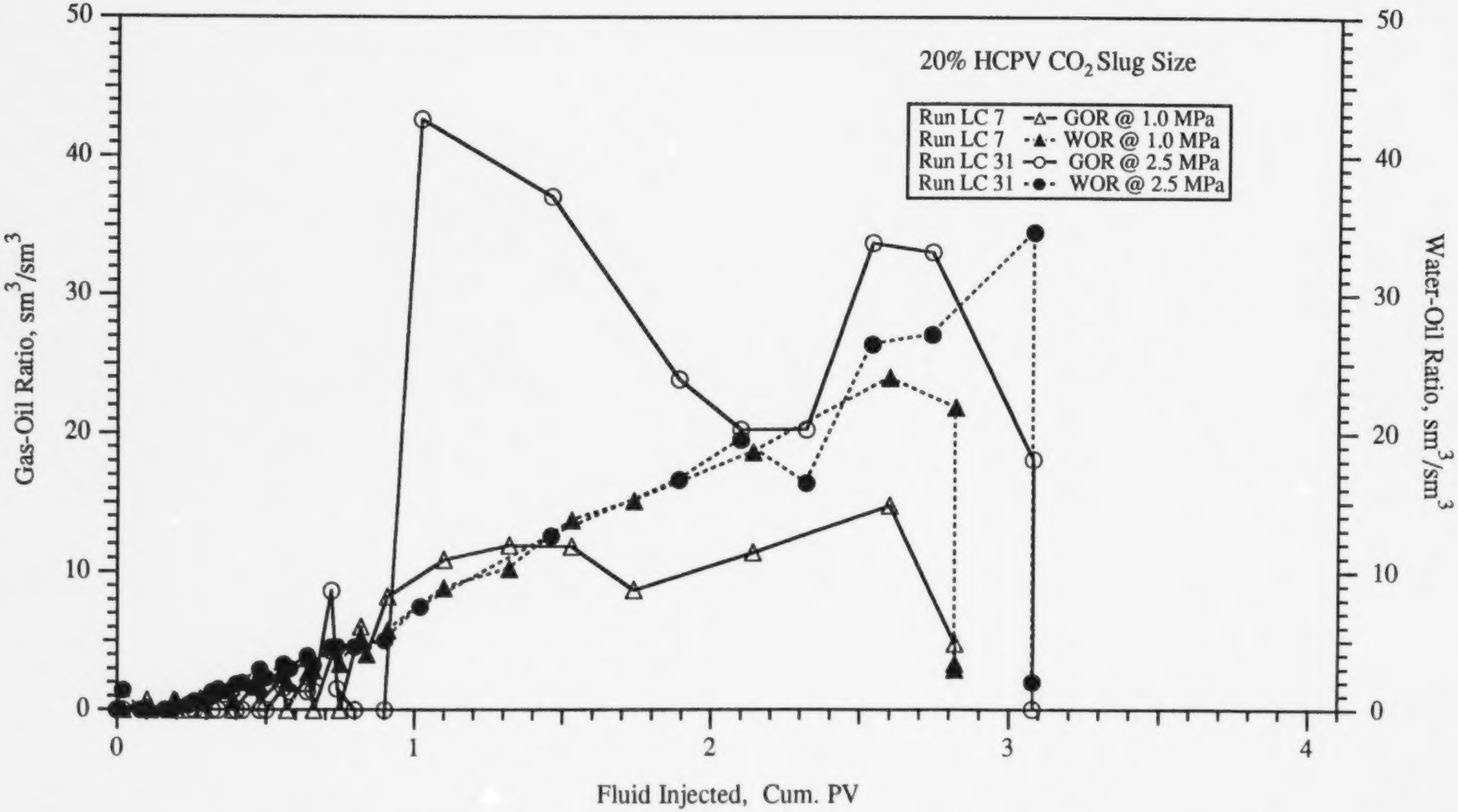


Figure 5.72: Production History of the Experiments using a 20% HCPV Carbon Dioxide Slug Size @ 1.0 (Ref.6) and 2.5 MPa.
Linear Model Experiments.

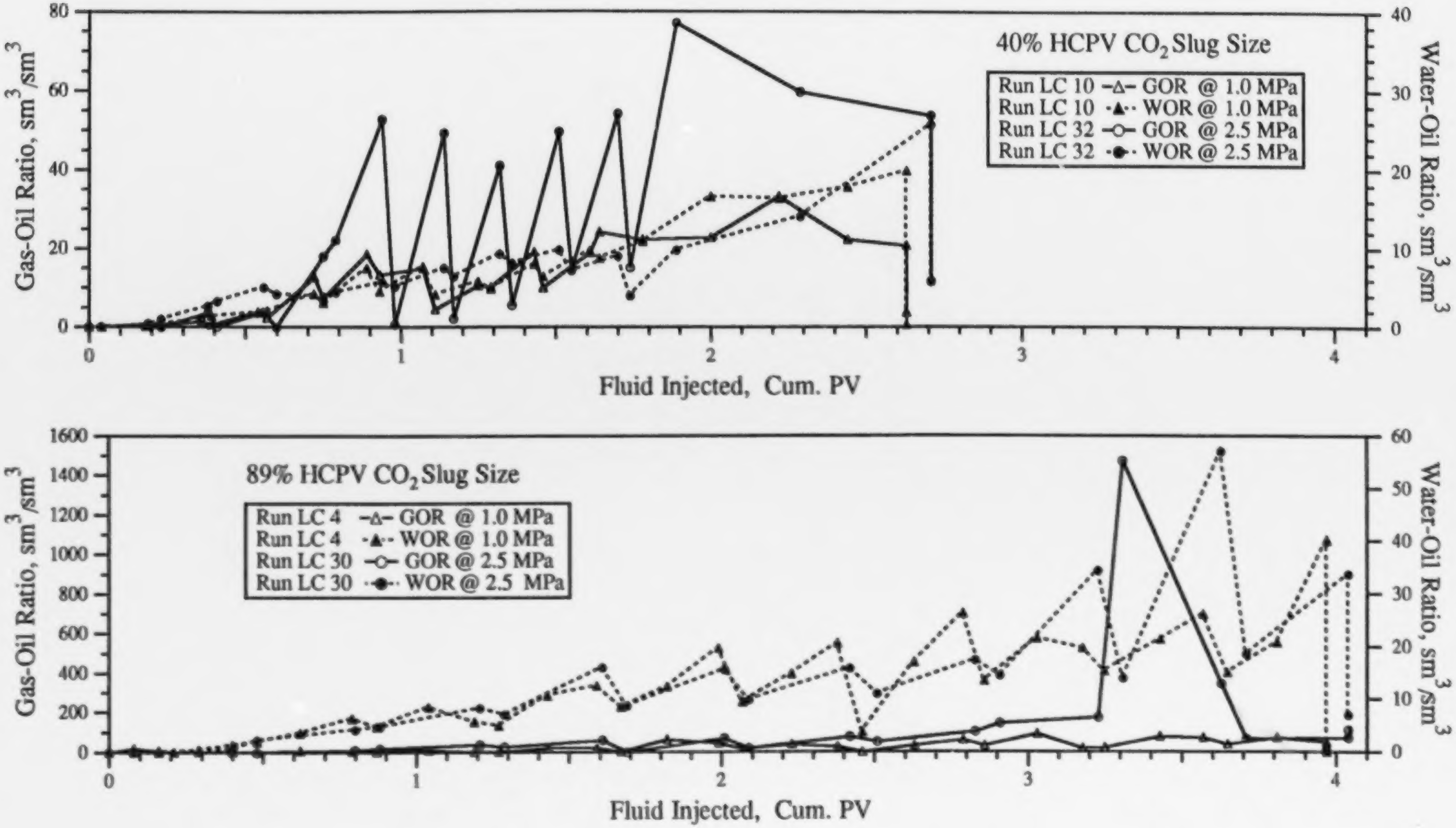


Figure 5.73: Comparison of the Production Histories for the 40% and 89% HCPV Carbon Dioxide Slug Sizes at 1.0 and 2.5 MPa. Linear Model Experiments.

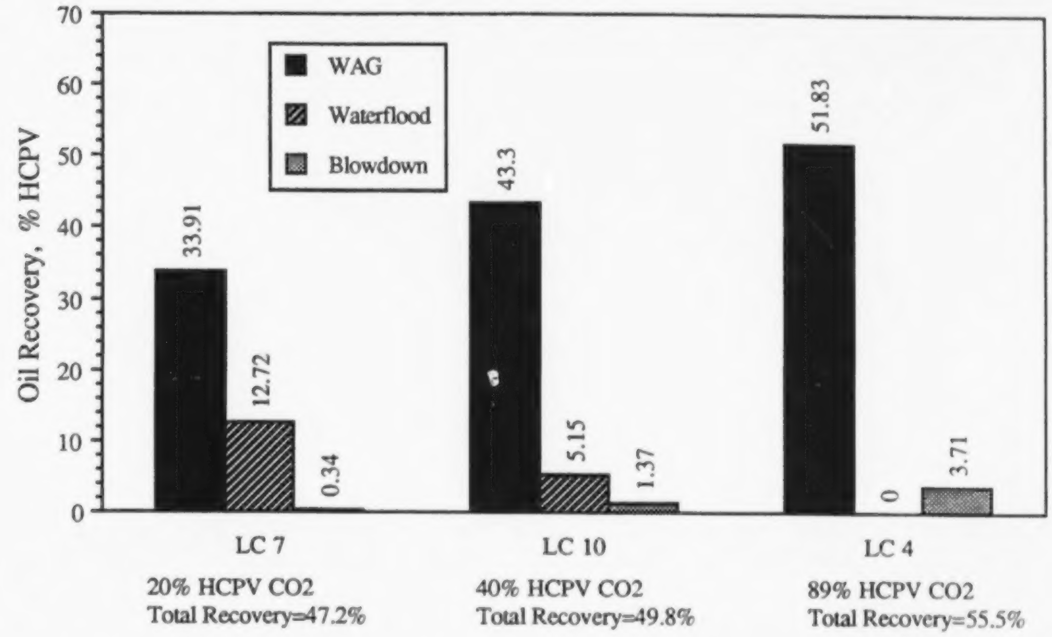


Figure 5.74: Oil Recovery Distribution of Different Phases of the Experiments @ 1.0 MPa.

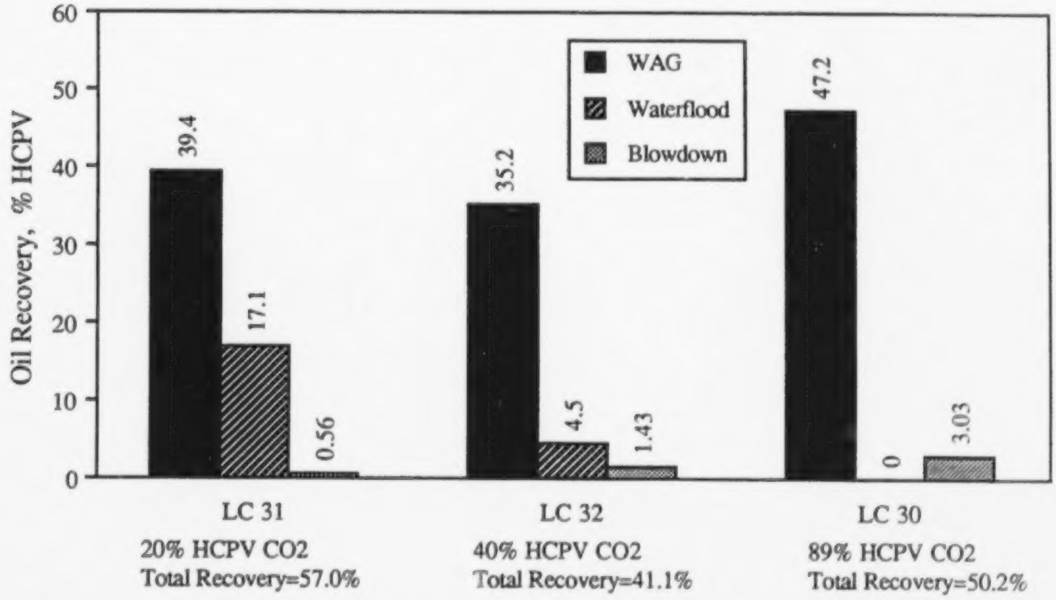


Figure 5.75: Oil Recovery Distribution of Different Phases of the Experiments @ 2.5 MPa.

Figure 5.76 represents the effect of different phases on the oil recovery for different experiments at 2.5 MPa. Here, the results show that, in general, the WAG recovery increased with the slug size while the waterflood recovery reached a maximum for the smallest slug size used, because such a small slug was not very effective in the WAG process and thus there was a considerable volume of oil left which was recovered by the waterflood process. The blowdown recovery for all the experiments is nearly the same for this group of experiments. The total oil recovery curve shows that the maximum recovery was obtained when using a 20% HCPV slug of carbon dioxide. Thus for an effective process, oil recovery from all three phases of the process is important.

Figures 5.77 and 5.78 show the carbon dioxide requirement and retention for the experiments (Ref.6) conducted at 1.0 MPa and 2.5 MPa, respectively. It is clearly demonstrated from both diagrams that a 20% slug size had the least carbon dioxide requirement, i.e. small volumes of carbon dioxide gas are required to produce oil. The larger slug size (89%), had a high carbon dioxide requirement value indicating that it was not as efficient as when utilizing smaller slugs. The estimation of the carbon dioxide retention showed that, in general, the carbon dioxide retention increased with slug size and also with an increase in pressure, as the gas is more soluble in oil at higher pressures.

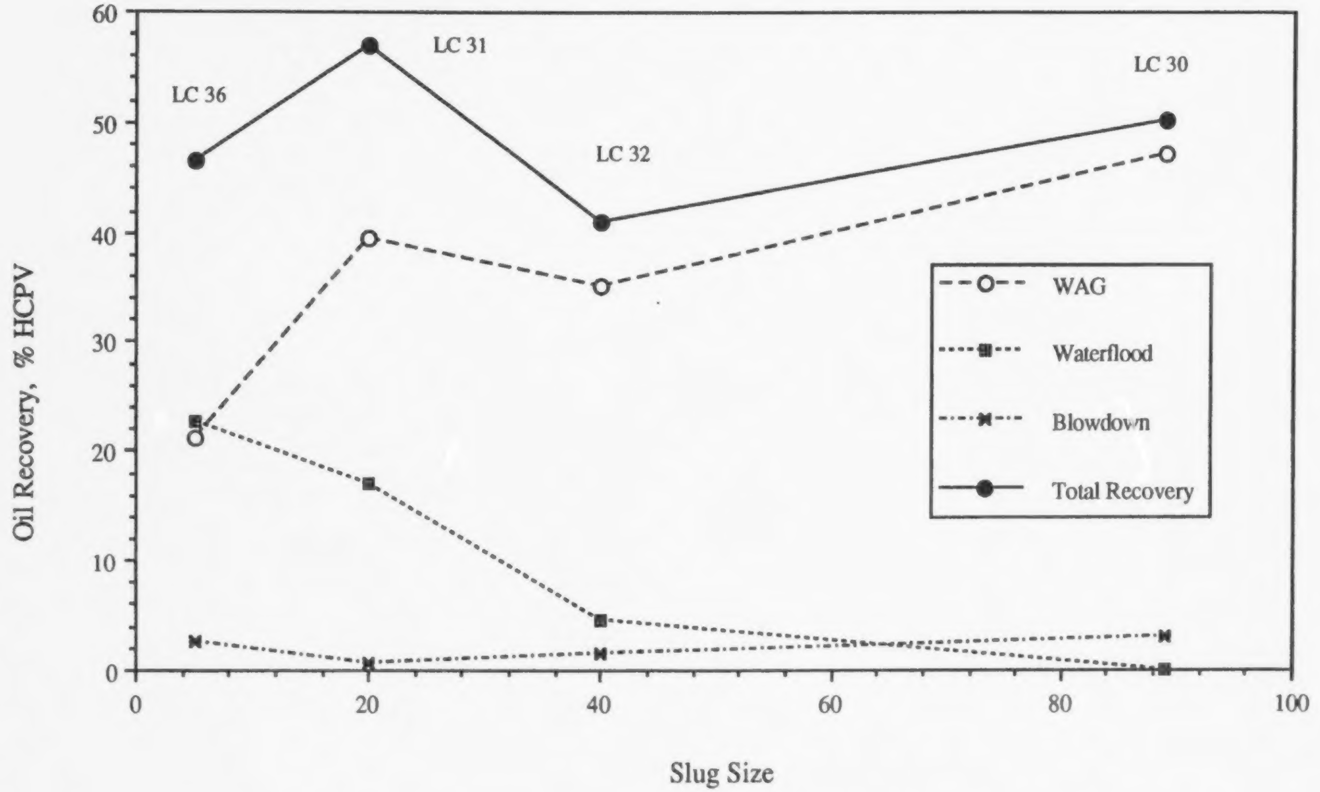


Figure 5.76: Effect of the Different Phases on Oil Recovery for Linear Model Experiments @ 2.5 MPa, 4:1 WAG, 10 Slugs and v=0.98 m/d.

Figure 5.77: Carbon Dioxide Requirement and Retention Values for Different Slug Sizes @ 1.0 MPa. (Ref.6)

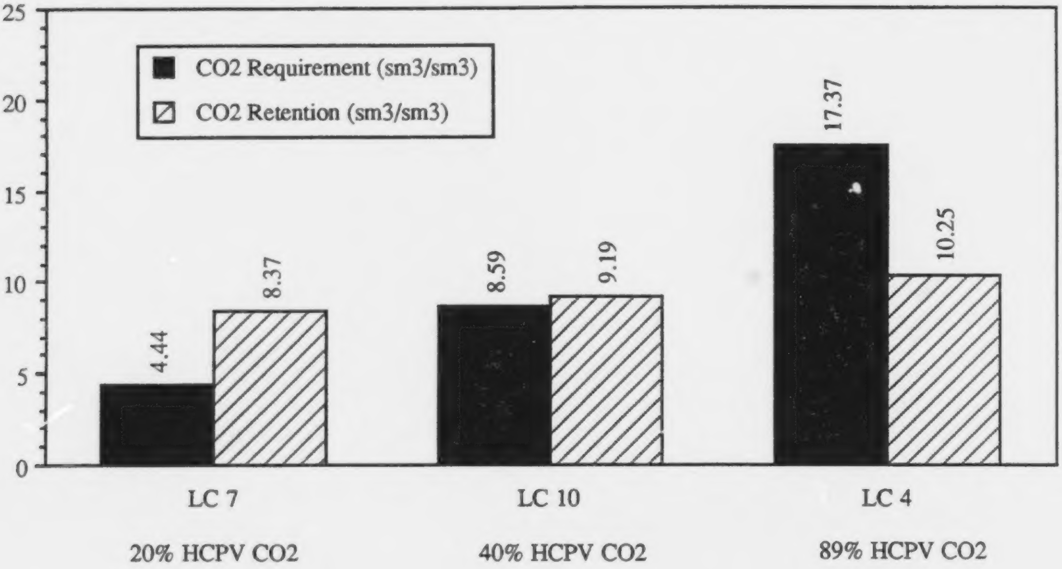
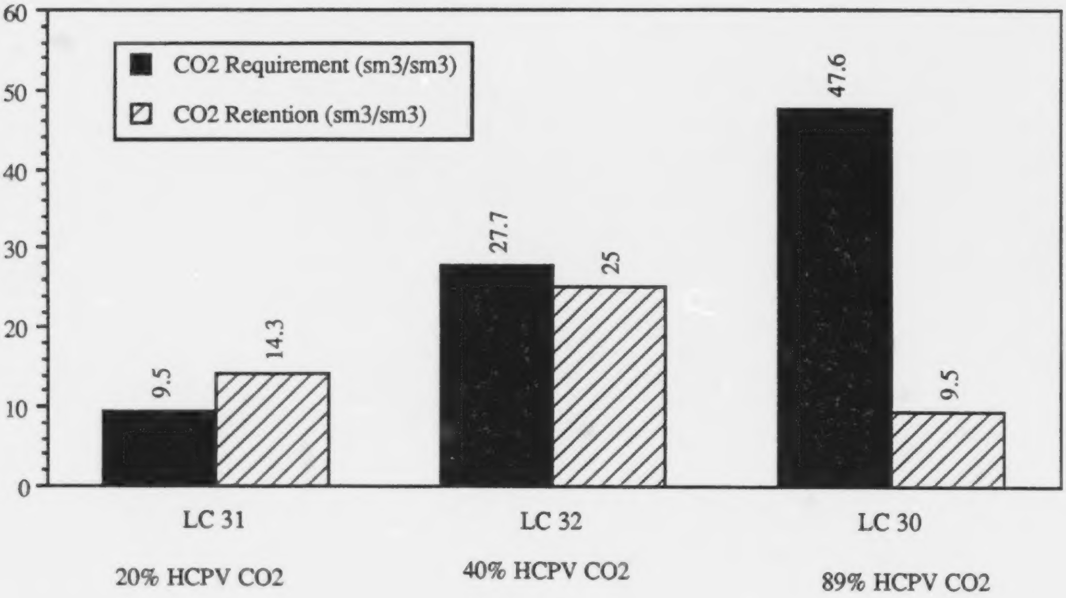


Figure 5.78: Carbon Dioxide Requirement and Retention for Different Slug Sizes @ 2.5 MPa.



6. CONCLUSIONS

This study was concerned with the effect of pressure and flow velocity on the immiscible carbon dioxide flooding process. A total of twenty-five experiments were conducted in one- and two-dimensional scaled laboratory models, and the following conclusions were reached:

1. Oil recovery by the immiscible carbon dioxide flooding process increases with an increase in the total volume of carbon dioxide injected. Larger slugs result in less efficient utilization of carbon dioxide as reflected by the carbon dioxide requirement and gas-oil ratio. (e.g. the requirement was 4.3 sm^3/sm^3 for the 20% slug vs. 6.6 sm^3/sm^3 for the 40% slug for the live oil experiments. The carbon dioxide requirement was 9.5 sm^3/sm^3 for the 20% slug vs. 27.7 sm^3/sm^3 for the 40% slug for the dead oil experiments).

2. From a study of the different slug sizes utilized for the experiments, a 20% HCPV carbon dioxide slug size was most effective for the laboratory experiments. This agrees with the results from the previous work, where it was observed that the optimum slug size was in this range.

3. It is important to consider the individual contributions of the WAG, waterflood and the blowdown phases to the total oil recovery in any interpretation of the process mechanism. The WAG recovery was important in experiments when considering the WAG phase recovery alone; the larger slug used had greater oil recoveries (e.g. Runs LC 30, LC 38, GTD 4, GTD 7 and GTD 10), while the blowdown recovery was the main factor in tertiary floods.

4. In a few cases, oil recovery increased with a decrease in pressure. e.g. The oil recovery from Runs GTD 5, GTD 6 and GTD 7 (1.0 MPa experiments) were greater than those of Runs GTD 2, GTD 3, GTD 4 (2.5 MPa experiments) when using identical experimental parameters.

5. When considering the flow velocity, it was found that oil recovery increased with an increase in flow velocity. e.g. Runs GTD 5, GTD 6, and GTD 7 (2.6 m/d) were able to recover more oil than Runs GTD 8, GTD 9 and GTD 10 (1.3 m/d).

6. The immiscible carbon dioxide WAG process was able to mobilize residual oil and thus can be used effectively as an enhanced recovery process. In the linear model, for a dead oil sample at 2.5 MPa, the residual oil recovery was 34.3% RHCPV and for the live oil sample at 1.0 MPa, the residual oil recovery was 27.6% RHCPV.

7. The tertiary run (LC 34), conducted in the linear model at 2.5 MPa using dead oil , had a total oil recovery of 61.7%, of which, 20.2% was the incremental recovery over the waterflood. The total oil recovery of the secondary WAG runs was in the range of 42%-57%. For the case of the live oil run (LC 43), conducted in the linear model at 1.0 MPa, the total tertiary oil recovery was 67.6%, of which 12.3% was the incremental recovery over the waterflood. The total oil recovery of the secondary runs was in the range of 62.5%-66%. Thus it can be concluded that the tertiary flood was able to recover more oil than the secondary flood.

7. In the case of a live oil, the total oil recovery was relatively higher (62.5% for the 10% slug, 65.0% for the 20% slug and 64.7% for the 40% slug) than the recoveries obtained from dead oil experiment (51.1% for the 20% slug, i.e. Run LC 42) and was almost constant for slug sizes of 10, 20 and 30% HCPV of carbon dioxide, but recovery during the individual phases of the process varied widely.

7. RECOMMENDATIONS FOR FURTHER RESEARCH

The following recommendations are offered for further study in the area of immiscible carbon dioxide WAG process.

1. Introduce a gas chromatograph into the downstream measuring system whereby the effluents are analyzed, and thus confirm the effect of methane as a lean gas and its effect on recovery as an agent contributing to the internal drive energy. Each slug could be analyzed individually and the effect of methane noted on the total percent of oil recovered.

2. Use other gases which have viscosity reducing properties, like propane, and note their effect on recovery when compared to the use of carbon dioxide.

3. Conduct experiments by positioning the model vertically instead of horizontally, and inject gas from the bottom to evaluate and compare the performance. Also, this would help to analyze the gravity force and its effect on the recovery process.

4. Determine the extent to which a soak period would affect recovery, as the soak period would help the carbon dioxide diffuse into the oil. This could be implemented by either exposing the oil to a source of carbon dioxide gas and pressurizing the model by using the gas to do so, or by mixing the oil and gas in a mixing chamber.

5. Utilize a bottom water layer to judge the sensitivity of the process to carbon dioxide dissolution and channelling into the water zone.

6. Devise a sound method for measuring the volume of produced gases. It was noticed from this study that in a few experiments the present equipment was not sensitive enough to provide reliable gas volumes, particularly when the gas volume was very small.

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Appendix A

Density Calculation for the Oil Sample

The density of the oil sample was measured using a Paar DMA 600 density meter. The measurement procedure used was from the laboratory manual and the data was collected as follows:

1. $T_{air} = T_2 = 0.69166$
2. $T_{distilled\ water} = T_1 = 0.76381$
3. $T_{oil} = T_s = 0.75930$
4. T = room temperature = 23.0°C
5. H = barometric pressure = 69.5 cm of Hg
6. Calculate the density of air (gm/cc) from

$$\rho_{air} = \rho_2 = \frac{0.001293}{1+0.00367T} \cdot \frac{H}{76} = 0.00109 \text{ gm/cc.}$$

7. Obtain the density of distilled water, ρ_1.

$$\rho_1 = 0.997534 \text{ gm/cc.}$$

8. Determine the densitometer calibration constant, K, from the formula:

$$K = \frac{\rho_1 - \rho_2}{T_1^2 - T_2^2} = \frac{0.997534 - 0.00109}{0.76381^2 - 0.691611^2}$$
$$= 9.4827.$$

9. The density (gm/cc) for the sample:

$$\begin{aligned} \rho_s &= \rho_1 + [\ (T_s^2 - T_1^2)K\ ] \\ &= 0.997534 + [\ (0.75930^2 - 0.76381^2)9.4827\ ] \\ &= 0.9324 \text{ gm / cc.} \end{aligned}$$

Assuming the density of water $\rho_{water} = 1.0$ gm / cc

$$\therefore \text{SG} = 0.9324.$$

To calculate the molecular weight using Cragoe's equation

$$MW = \frac{44.25SG}{1.0298 - SG} \equiv 424.00 \text{ kg / k.mol.}$$

Appendix B

Live Oil Viscosity Calculations

The viscosity of the live oil sample was calculated using the correlation presented by Puttagunta, Singh and Cooper.[65]

To calculate the live oil viscosity at room temperature, the values of the following parameters were required

1. Density of the Aberfeldy oil = 0.9324 gm/cc = 932.4 kg/m^3 (Appendix A)
   Viscosity of the dead oil @ 23 °C = 1046 mPa.s
2. Density of methane gas @ 20.6 °C and 0.095 MPa = 0.6583 kg/m^3
   Molecular weight of methane = 16.042 kg/k.mol
3. Calculated GOR of the oil and methane mixture = 3.3 sm^3/sm^3
4. Molecular weight of oil = 424 kg/k.mol (Appendix A)

Properties of the mixture:

Assuming a total of 1 m^3 of oil,
Methane: 3.3 sm^3 x 0.6583 kg/m^3 = 2.1724 kg
2.1724 kg / 16.042 kg/k-mol = 0.1354 k.mol
Oil: 1 sm^3 of oil x 932.4 kg/m^3 = 932.4 kg
932.4 kg / 424 kg/k-mol = 2.1991 k-mol
∴ Total moles = 0.1354 + 2.1991 = 2.3345 k-mol

The procedure then followed:

1. Assume an initial value of the oil viscosity, μ_o.

2. Obtain b:

   $b = \log \mu_{o(30°C,\ 0\ MPa)} + 3.002$, where μ_o is in Pa.s.

3. Obtain s, B_o, and d:

   $s = 0.0066940 \times b + 3.5364$
   $B_o = 0.0047424 \times b + 0.0081709$
   $d = -0.0015646 \times b + 0.0061814$

4. $$\ln \mu_{oT,P,X} = 2.3026\left(\frac{b}{(1+\frac{T-30}{303.15})^{s}} - 3.002 \right)$$

The assumed value of viscosity was compared by trial and error to match the experimental value, as is shown in Table 1. Then the other constants were calculated to substitute in the main equation.

5. The concentration, X, calculated for the additive methane in mole percent:

$$X = \frac{\text{moles additive}}{\text{moles oil} + \text{moles additive}} \text{ x } 100$$

$$X = \frac{0.1354}{2.3345} \text{ x } 100 = 5.8 \text{ mol } \%.$$

6. Obtain C_o and E for the desired additive, methane.

C_o = 0.031396 x b - 0.031399.

E = 0.0024696 x b - 0.0017938.

7. All the calculated values were substituted in the following equation

$$\ln \mu_{oT,P,X} = 2.3026\left(\frac{b}{(1+\frac{T-30}{303.15})^{s}} - 3.002 \right) + B_o \,.\, P \,.\, \exp(d \,.\, T) - C_o \,.\, X \,.\, \exp(-E \,.\, T).$$

The calculated values were presented in Table B1.

The calculated viscosity was based on the molar value
μ_o = 783.83 mPa.s @ atmospheric pressure, and μ_o = 801.83 mPa.s @ 1 MPa.

The estimated error was less than 6.3 %
$\therefore \mu_o = 783.8 \pm 49$ mPa.s.

Table 1: Calculation of live oil viscosity.

Trial	μ	b	s	Bo	d	Co	E	ln (Mu)	μ	μ
	Pa.s					Methane, mole %			Pa.s	mPa.s
	(Mu is the initial guess)									
1	0.601	2.7809	3.5550	0.0214	0.0018	0.0559	0.0051	0.0453	1.0464	1046.38
2	0.602	2.7816	3.5550	0.0214	0.0018	0.0559	0.0051	0.0471	1.0483	1048.28
3	0.605	2.7838	3.5550	0.0214	0.0018	0.0560	0.0051	0.0526	1.0540	1053.96
4	0.6005	2.7805	3.5550	0.0214	0.0018	0.0559	0.0051	0.0444	1.0454	1045.44
5	0.6008	2.7807	3.5550	0.0214	0.0018	0.0559	0.0051	0.0450	1.0460	1046.00
6	0.601	2.7809	3.5550	0.0214	0.0018	0.0559	0.0051	0.0453	1.0464	1046.38
7	0.602	2.7816	3.5550	0.0214	0.0018	0.0559	0.0051	0.0471	1.0483	1048.28
8	0.605	2.7838	3.5550	0.0214	0.0018	0.0560	0.0051	0.0526	1.0540	1053.96
9	0.6005	2.7805	3.5550	0.0214	0.0018	0.0559	0.0051	0.0444	1.0454	1045.44
10	0.6008	2.7807	3.5550	0.0214	0.0018	0.0559	0.0051	0.0450	1.0460	1046.00

Trial	X %	T °C	P (MPa)	(ln Mu) T,P,X	μ	μ
					Pa.s	mPa.s
1	5.8	23	1	-0.22094	0.8018	801.77
2	5.8	23	1	-0.21923	0.8031	803.13
3	5.8	23	1	-0.21414	0.8072	807.24
4	5.8	23	1	-0.22179	0.8011	801.08
5	5.8	23	1	-0.22128	0.8015	801.49
6	5.8	23	0	-0.24322	0.7841	784.10
7	5.8	23	0	-0.24151	0.7854	785.44
8	5.8	23	0	-0.23643	0.7894	789.44
9	5.8	23	0	-0.24407	0.7834	783.43
10	5.8	23	0	-0.24356	0.7838	783.83

Notes : All the Calculations are Done on a Molar Basis.
The Initial Viscosity Guess is Taken to Be Between 0.601 - 0.6008 Pa.s
The Viscosity of the Live Oil is Approximately 783.8 mPa.s @ 0.0 MPa and 801.5 mPa.s @ 1.0 MPa.

Appendix C

This section contains the tabulated data for all the experiments.

TABLE A 1

RESULTS OF RUN GTD 1

[0.02 HCPV CO2 @ 2.5 MPa (0.42 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

Porosity [%] = 41.6
Oil Viscosity [mPa.s] = 1230.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 19.72

Pore Volume [cm3] = 2024.0
Initial Oil Saturation [%] = 85.9
Hydrocarbon Pore Volume [cm3] = 1740.2
Carbon Dioxide Retention [%inj] = 95.44

Connate Water Saturation [%] = 14.1
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 13.6100
Average Flow Velocity [m/d] = 1.290

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.50	2.00	34.9	0.0	0.017	0.000	0.10	0.10	0.10	0.01	1.00	0.00	0.003
3.00	2.50	0.0	139.2	0.069	0.000	11.50	104.00	104.10	5.98	0.11	0.00	0.747
3.00	2.50	34.9	0.0	0.017	0.000	0.00	5.00	109.10	6.27	0.00	0.00	0.143
2.80	2.50	0.0	139.2	0.069	0.000	12.20	127.80	236.90	13.61	0.10	0.00	0.918
2.60	2.50	34.9	0.0	0.017	0.000	0.00	2.50	239.40	13.76	0.00	0.00	0.072
2.80	2.50	0.0	139.2	0.069	0.000	73.00	60.50	299.90	17.23	1.21	0.00	0.435
2.60	2.50	39.8	0.0	0.020	0.000	2.00	3.80	303.70	17.45	0.53	0.00	0.096
2.60	2.50	0.0	139.2	0.069	0.000	100.00	38.00	341.70	19.64	2.63	0.00	0.273
2.60	2.50	34.9	0.0	0.017	0.000	2.75	2.75	344.45	19.79	1.00	0.00	0.079
2.60	2.50	0.0	139.2	0.069	0.000	102.00	33.50	377.95	21.72	3.04	0.00	0.241
2.60	2.50	34.9	0.0	0.017	0.008	4.50	2.20	380.15	21.85	2.05	3.64	0.063
2.50	2.40	0.0	139.2	0.069	0.002	105.00	32.00	412.15	23.68	3.28	0.06	0.230
2.60	2.50	46.4	0.0	0.023	0.000	6.00	1.50	413.65	23.77	4.00	0.00	0.032
2.00	2.00	0.0	140.1	0.069	0.001	108.00	28.00	441.65	25.38	3.86	0.04	0.200
2.50	2.50	36.3	0.0	0.018	0.000	5.90	1.90	443.55	25.49	3.11	0.00	0.052
2.50	2.50	0.0	139.3	0.069	0.018	118.00	17.00	460.55	26.47	6.94	1.06	0.122
2.50	2.50	34.9	0.0	0.017	0.000	2.40	2.50	463.05	26.61	0.96	0.00	0.072

TABLE A 1 (CONTINUED)

RESULTS OF RUN GTD 1
[0.02 HCPV CO2 @ 2.5 MPa (0.42 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

Porosity [%] = 41.6
Oil Viscosity [mPa.s] = 1230.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 19.72

Pore Volume [cm3] = 2024.0
Initial Oil Saturation [%] = 85.9
Hydrocarbon Pore Volume [cm3] = 1740.2
Carbon Dioxide Retention [%inj] = 95.44

Connate Water Saturation [%] = 14.1
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 13.6100
Average Flow Velocity [m/d] = 1.290

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.56	2.50	0.0	140.2	0.069	0.009	112.00	15.80	478.85	27.52	7.09	0.57	0.113
2.54	2.48	38.8	0.0	0.019	0.000	6.50	1.30	480.15	27.59	5.00	0.00	0.034
2.50	2.50	0.0	139.2	0.069	0.052	130.00	8.00	488.15	28.05	16.25	6.50	0.057
2.50	2.50	0.0	235.5	0.116	0.053	214.00	14.00	502.15	28.86	15.29	3.79	0.059
2.50	2.50	0.0	180.8	0.089	0.109	172.00	11.00	513.15	29.49	15.64	9.91	0.061
2.54	2.50	0.0	177.6	0.088	0.090	167.00	10.00	523.15	30.06	16.70	9.00	0.056
2.50	2.50	0.0	233.5	0.115	0.090	215.00	12.90	536.05	30.80	16.67	6.98	0.055
2.60	2.50	0.0	258.2	0.128	0.046	248.00	12.00	548.05	31.49	20.67	3.83	0.046
2.50	2.50	0.0	295.0	0.146	0.032	270.00	16.00	564.05	32.41	16.88	2.00	0.054
0.10	0.10	0.0	0.0	0.000	0.004	46.00	7.00	571.05	32.82	6.57	0.57	

TABLE A 2

RESULTS OF RUN GTD 2
[0.20 HCPV CO2 @ 2.5 MPa (0.445 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

Porosity [%] = 41.6
Oil Viscosity [mPa.s] = 1115.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 16.31

Pore Volume [cm3] = 2025.0
Initial Oil Saturation [%] = 91.3
Hydrocarbon Pore Volume [cm3] = 1849.3
Carbon Dioxide Retention [%inj] = 35.48

Connate Water Saturation [%] = 8.7
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 13.9400
Average Flow Velocity [m/d] = 1.550

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.60	2.50	36.9	0.0	0.018	0.000	0.01	0.01	0.01	0.00	1.00	0.00	0.000
2.90	2.50	0.0	148.0	0.073	0.042	0.00	128.50	128.51	6.95	0.00	0.33	0.868
2.80	2.50	0.0	36.9	0.018	0.001	0.00	20.00	148.51	8.03	0.00	0.05	0.542
2.80	2.50	0.0	148.4	0.073	0.278	7.00	126.50	275.01	14.87	0.06	2.20	0.853
2.75	2.50	36.9	0.0	0.018	0.000	18.75	13.25	288.26	15.59	1.42	0.00	0.359
2.75	2.50	0.0	148.0	0.073	0.031	46.25	79.50	367.76	19.89	0.58	0.39	0.537
2.60	2.45	36.9	0.0	0.018	0.000	18.00	10.75	378.51	20.47	1.67	0.00	0.291
2.60	2.50	0.0	148.0	0.073	0.048	94.00	34.00	412.51	22.31	2.76	1.41	0.230
2.66	2.50	37.0	0.0	0.018	0.003	17.00	5.00	417.51	22.58	3.40	0.60	0.135
2.50	2.50	0.0	148.0	0.073	0.107	113.00	23.00	440.51	23.82	4.91	4.65	0.155
2.60	2.60	37.0	0.0	0.018	0.025	21.00	4.75	445.26	24.08	4.42	5.26	0.128
2.50	2.40	0.0	148.0	0.073	0.407	96.50	17.00	462.26	25.00	5.68	23.94	0.115
2.60	2.60	37.0	0.0	0.018	0.068	23.75	9.25	471.51	25.50	2.57	7.35	0.250
2.50	2.50	0.0	148.0	0.073	1.000	106.00	18.50	490.01	26.50	5.73	54.05	0.125
2.50	2.50	37.0	0.0	0.018	0.039	16.00	2.00	492.01	26.61	8.00	19.50	0.054
3.00	2.80	0.0	147.9	0.073	0.690	106.00	25.00	517.01	27.96	4.24	27.60	0.169
3.00	2.80	37.2	0.0	0.018	0.051	15.00	1.75	518.76	28.05	8.57	29.14	0.047

TABLE A 2 (CONTINUED)

RESULTS OF RUN GTD 2
[0.20 HCPV CO2 @ 2.5 MPa (0.445 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

Porosity [%] = 41.6
Oil Viscosity [mPa.s] = 1115.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 16.31
Pore Volume [cm3] = 2025.0
Initial Oil Saturation [%] = 91.3
Hydrocarbon Pore Volume [cm3] = 1849.3
Carbon Dioxide Retention [%inj] = 35.48
Connate Water Saturation [%] = 8.7
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 13.9400
Average Flow Velocity [m/d] = 1.550

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.40	2.30	0.0	149.2	0.074	0.690	119.50	7.50	526.26	28.46	15.93	92.00	0.050
2.30	2.30	37.0	0.0	0.018	0.025	8.00	1.75	528.01	28.55	4.57	14.29	0.047
2.50	2.40	0.0	148.0	0.073	0.700	129.50	10.50	538.51	29.12	12.33	66.67	0.071
2.50	2.50	0.0	166.8	0.082	0.740	152.00	10.00	548.51	29.66	15.20	74.00	0.060
2.40	2.40	0.0	281.6	0.139	1.006	266.00	26.50	575.01	31.09	10.04	37.96	0.094
2.50	2.50	0.0	440.3	0.217	0.587	414.00	45.00	620.01	33.53	9.20	13.04	0.102
2.50	2.50	0.0	61.3	0.030	0.040	38.00	1.75	621.76	33.62	21.71	22.86	0.029
0.10	0.10	0.0	0.0	0.000	0.014	26.00	4.50	626.26	33.87	5.78	3.11	

TABLE A 3

RESULTS OF RUN GTD 3
[0.10 HCPV CO2 @ 2.5 MPa (0.445 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

Porosity [%] = 41.1
Oil Viscosity [mPa.s] = 1115.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 7.26

Pore Volume [cm3] = 2004.0
Initial Oil Saturation [%] = 91.3
Hydrocarbon Pore Volume [cm3] = 1795.6
Carbon Dioxide Retention [%inj] = 99.08

Connate Water Saturation [%] = 8.7
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 18.6800
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.80	2.60	18.2	0.0	0.009	0.000	0.00	4.50	4.50	0.25	0.00	0.00	0.248
3.10	2.50	0.0	72.2	0.036	0.000	0.00	65.50	70.00	3.90	0.00	0.00	0.907
2.80	2.50	18.2	0.0	0.009	0.000	0.00	7.90	77.90	4.34	0.00	0.00	0.435
3.10	2.50	0.0	71.7	0.036	0.000	2.00	68.75	146.65	8.17	0.03	0.00	0.958
2.80	2.50	18.2	0.0	0.009	0.000	1.50	9.70	156.35	8.71	0.15	0.00	0.534
2.60	2.50	0.0	71.8	0.036	0.000	6.50	60.00	216.35	12.05	0.11	0.00	0.836
2.50	2.20	18.2	0.0	0.009	0.000	5.00	11.50	227.85	12.69	0.43	0.00	0.633
2.50	2.40	0.0	71.8	0.036	0.000	11.00	50.00	277.85	15.47	0.22	0.00	0.696
2.50	2.40	18.2	0.0	0.009	0.000	5.00	10.00	287.85	16.03	0.50	0.00	0.551
2.50	2.30	0.0	71.9	0.036	0.000	19.00	42.00	329.85	18.37	0.45	0.00	0.585
2.60	2.20	18.2	0.0	0.009	0.000	5.00	6.75	336.60	18.75	0.74	0.00	0.372
2.50	2.20	0.0	72.6	0.036	0.000	28.00	34.50	371.10	20.67	0.81	0.00	0.475
2.50	2.20	18.2	0.0	0.009	0.000	8.20	6.80	377.90	21.05	1.21	0.00	0.374
2.50	2.20	0.0	71.8	0.036	0.000	30.00	30.00	407.90	22.72	1.00	0.00	0.418
2.50	2.20	18.2	0.0	0.009	0.000	12.00	6.75	414.65	23.09	1.78	0.00	0.372
2.50	2.28	0.0	71.9	0.036	0.000	28.00	28.50	443.15	24.68	0.98	0.00	0.396
2.50	2.30	18.2	0.0	0.009	0.000	8.75	4.25	447.40	24.92	2.06	0.00	0.234

TABLE A 3 (CONTINUED)

RESULTS OF RUN GTD 3
[0.10 HCPV CO2 @ 2.5 MPa (0.445 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

Porosity [%] = 41.1
Oil Viscosity [mPa.s] = 1115.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 7.26

Pore Volume [cm3] = 2004.0
Initial Oil Saturation [%] = 91.3
Hydrocarbon Pore Volume [cm3] = 1795.6
Carbon Dioxide Retention [%inj] = 99.08

Connate Water Saturation [%] = 8.7
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 18.6800
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.50	2.40	0.0	72.8	0.036	0.000	45.00	19.00	466.40	25.97	2.37	0.00	0.261
2.60	2.20	18.2	0.0	0.009	0.000	15.00	4.75	471.15	26.24	3.16	0.00	0.262
2.50	2.20	0.0	71.8	0.036	0.000	43.00	13.50	484.65	26.99	3.19	0.00	0.188
2.50	2.30	0.0	181.9	0.091	0.032	132.00	36.00	520.65	29.00	3.67	0.89	0.198
2.50	2.10	0.0	245.5	0.123	0.006	205.00	51.00	571.65	31.84	4.02	0.12	0.208
2.50	2.20	0.0	271.1	0.135	0.000	222.00	26.00	597.65	33.28	8.54	0.00	0.096
2.50	2.20	0.0	245.9	0.123	0.000	223.00	34.00	631.65	35.18	6.56	0.00	0.138
2.60	2.40	0.0	119.4	0.060	0.000	104.00	10.00	641.65	35.73	10.40	0.00	0.084
2.50	2.30	0.0	470.7	0.235	0.000	443.00	31.00	672.65	37.46	14.29	0.00	0.066
2.50	2.30	0.0	476.2	0.238	0.000	462.00	23.00	695.65	38.74	20.09	0.00	0.048
2.50	2.20	0.0	480.8	0.240	0.000	446.00	29.00	724.65	40.36	15.38	0.00	0.060
0.10	0.10	0.0	0.0	0.000	0.013	68.00	38.00	762.65	42.47	1.79	0.34	

TABLE A 4

RESULTS OF RUN GTD 4
[0.30 HCPV CO2 @ 2.5 MPa (0.682 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

Porosity [%] = 41.6
Oil Viscosity [mPa.s] = 1135.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 22.46
Pore Volume [cm3] = 2025.0
Initial Oil Saturation [%] = 93.2
Hydrocarbon Pore Volume [cm3] = 1887.1
Carbon Dioxide Retention [%inj] = 75.29
Connate Water Saturation [%] = 6.8
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 13.5700
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.90	2.40	75.1	0.0	0.037	0.000	0.20	26.30	26.30	1.39	0.01	0.00	0.350
2.90	2.20	0.0	226.5	0.112	0.000	7.00	190.50	216.80	11.49	0.04	0.00	0.841
2.70	2.20	55.7	0.0	0.028	0.000	8.30	26.80	243.60	12.91	0.31	0.00	0.481
2.70	2.20	0.0	226.5	0.112	0.000	97.50	104.00	347.60	18.42	0.94	0.00	0.459
2.50	2.20	55.7	0.0	0.028	0.000	30.00	15.10	362.70	19.22	1.99	0.00	0.271
2.50	2.20	0.0	226.8	0.112	0.000	142.00	53.00	415.70	22.03	2.68	0.00	0.234
2.50	2.20	55.7	0.0	0.028	0.000	31.00	8.00	423.70	22.45	3.88	0.00	0.144
2.50	2.20	0.0	226.5	0.112	0.000	156.00	33.00	456.70	24.20	4.73	0.00	0.146
2.50	2.20	55.7	0.0	0.028	0.000	35.50	7.40	464.10	24.59	4.80	0.00	0.133
2.50	2.30	0.0	226.5	0.112	0.000	160.50	29.50	493.60	26.16	5.44	0.00	0.130
2.48	2.30	55.7	0.0	0.028	0.000	32.20	4.90	498.50	26.42	6.57	0.00	0.088
2.50	2.30	0.0	226.5	0.112	0.007	163.80	26.40	524.90	27.82	6.20	0.27	0.117
2.50	2.30	55.7	0.0	0.028	0.008	42.20	6.30	531.20	28.15	6.70	1.27	0.113
2.48	2.30	0.0	226.6	0.112	0.007	169.60	18.40	549.60	29.12	9.22	0.38	0.081
2.50	2.40	55.7	0.0	0.028	0.003	33.00	3.60	553.20	29.31	9.17	0.83	0.065
2.50	2.30	0.0	253.8	0.125	0.005	184.50	25.70	578.90	30.68	7.18	0.19	0.101
2.45	2.40	55.7	0.0	0.028	0.005	30.50	3.50	582.40	30.86	8.71	1.43	0.063

TABLE A 4 (CONTINUED)

RESULTS OF RUN GTD 4
[0.30 HCPV CO2 @ 2.5 MPa (0.682 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

Porosity [%] = 41.6
Oil Viscosity [mPa.s] = 1135.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 22.46

Pore Volume [cm3] = 2025.0
Initial Oil Saturation [%] = 93.2
Hydrocarbon Pore Volume [cm3] = 1887.1
Carbon Dioxide Retention [%inj] = 75.29

Connate Water Saturation [%] = 6.8
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 13.5700
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.45	2.40	0.0	226.5	0.112	0.000	163.00	23.00	605.40	32.08	7.09	0.00	0.102
2.50	2.40	55.7	0.0	0.028	0.004	35.00	4.80	610.20	32.34	7.29	0.83	0.086
2.40	2.30	0.0	217.8	0.108	0.001	162.00	18.50	628.70	33.32	8.76	0.05	0.085
2.50	2.40	0.0	48.4	0.024	0.018	33.00	2.00	630.70	33.42	16.50	9.00	0.041
0.10	0.10	0.0	0.0	0.000	4.192	233.00	135.00	765.70	40.58	1.73	31.05	

TABLE A 5

RESULTS OF RUN GTD 5
[0.10 HCPV CO2 @ 1.0 MPa (0.078 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

Porosity [%] = 43.2
Oil Viscosity [mPa.s] = 1125.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.54

Pore Volume [cm3] = 2104.0
Initial Oil Saturation [%] = 85.6
Hydrocarbon Pore Volume [cm3] = 1801.3
Carbon Dioxide Retention [%inj] = 99.80

Connate Water Saturation [%] = 14.4
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 11.5200
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	1.00	16.8	0.0	0.008	0.000	0.00	0.50	0.50	0.03	0.00	0.00	0.030
1.60	1.00	0.0	72.2	0.034	0.000	0.00	68.00	68.50	3.80	0.00	0.00	0.942
1.20	1.00	16.8	0.0	0.008	0.000	0.00	5.60	74.10	4.11	0.00	0.00	0.333
1.30	0.90	0.0	72.1	0.034	0.000	0.00	61.50	135.60	7.53	0.00	0.00	0.854
1.30	0.90	16.8	0.0	0.008	0.000	0.00	7.00	142.60	7.92	0.00	0.00	0.416
1.20	0.95	0.0	72.0	0.034	0.000	0.00	68.00	210.60	11.69	0.00	0.00	0.944
1.30	0.95	20.2	0.0	0.010	0.000	0.50	9.80	220.40	12.24	0.05	0.00	0.486
1.20	0.95	0.0	72.0	0.034	0.000	9.00	58.80	279.20	15.50	0.15	0.00	0.816
1.20	0.99	20.2	0.0	0.010	0.000	2.80	8.20	287.40	15.95	0.34	0.00	0.407
1.25	0.90	0.0	72.1	0.034	0.000	20.00	44.50	331.90	18.43	0.45	0.00	0.617
1.20	0.95	20.2	0.0	0.010	0.000	3.00	7.30	339.20	18.83	0.41	0.00	0.362
1.15	0.95	0.0	72.1	0.034	0.000	26.00	40.50	379.70	21.08	0.64	0.00	0.562
1.10	0.98	16.8	0.0	0.008	0.000	7.30	5.60	385.30	21.39	1.30	0.00	0.333
1.00	0.88	72.2	0.0	0.034	0.000	35.50	25.50	410.80	22.81	1.39	0.00	0.353
1.10	0.98	16.8	0.0	0.008	0.000	9.50	5.40	416.20	23.11	1.76	0.00	0.321
1.02	0.90	0.0	72.1	0.034	0.000	49.00	19.00	435.20	24.16	2.58	0.00	0.264
1.00	0.98	20.2	0.0	0.010	0.000	10.00	3.00	438.20	24.33	3.33	0.00	0.149

TABLE A 5 (CONTINUED)

RESULTS OF RUN GTD 5
[0.10 HCPV CO2 @ 1.0 MPa (0.078 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

Porosity [%] = 43.2	Pore Volume [cm3] = 2104.0	Connate Water Saturation [%] = 14.4
Oil Viscosity [mPa.s] = 1125.0	Initial Oil Saturation [%] = 85.6	Molar Density @ atm. [kmol/m3] = 0.04166
Average Run Temperature [K] = 294.15	Hydrocarbon Pore Volume [cm3] = 1801.3	Absolute Permeability [darcies] = 11.5200
Carbon Dioxide Required [sm3/sm3] = 4.54	Carbon Dioxide Retention [%inj] = 99.80	Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	0.90	0.0	72.1	0.034	0.000	50.00	13.00	451.20	25.05	3.85	0.00	0.180
1.00	0.96	16.8	0.0	0.008	0.000	10.00	3.00	454.20	25.21	3.33	0.00	0.178
1.15	0.98	0.0	72.7	0.035	0.000	53.00	11.00	465.20	25.83	4.82	0.00	0.151
1.20	0.96	0.0	474.0	0.225	0.000	405.00	70.00	535.20	29.71	5.79	0.00	0.148
1.10	0.90	0.0	482.6	0.229	0.000	435.00	35.00	570.20	31.65	12.43	0.00	0.073
1.00	0.95	0.0	477.7	0.227	0.000	450.00	30.00	600.20	33.32	15.00	0.00	0.063
1.02	0.98	0.0	479.8	0.228	0.000	459.00	23.00	623.20	34.60	19.96	0.00	0.048
1.00	0.98	0.0	48.0	0.023	0.000	46.00	4.00	627.20	34.82	11.50	0.00	0.083
0.10	0.10	0.0	0.0	0.000	0.000	84.00	18.00	645.20	35.82	4.67	0.00	

TABLE A 6

RESULTS OF RUN GTD 6

[0.20 HCPV CO2 @ 1.0 MPa (0.151 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

Porosity [%] = 42.1
Oil Viscosity [mPa.s] = 1175.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.03

Pore Volume [cm3] = 2050.0
Initial Oil Saturation [%] = 84.9
Hydrocarbon Pore Volume [cm3] = 1741.3
Carbon Dioxide Retention [%inj] = 53.96

Connate Water Saturation [%] = 15.1
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 14.5200
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	0.80	43.7	0.0	0.021	0.000	0.00	1.00	1.00	0.06	0.00	0.00	0.023
1.00	0.65	0.0	137.8	0.067	0.000	0.00	138.00	139.00	7.98	0.00	0.00	1.001
1.00	0.50	33.6	0.0	0.016	0.000	0.00	19.00	158.00	9.07	0.00	0.00	0.565
1.00	0.40	0.0	139.3	0.068	0.000	8.00	118.50	276.50	15.88	0.07	0.00	0.850
1.00	0.40	33.6	0.0	0.016	0.001	7.00	11.90	288.40	16.56	0.59	0.08	0.354
1.00	0.55	0.0	139.4	0.068	0.002	55.00	64.50	352.90	20.27	0.85	0.02	0.463
1.00	0.50	33.6	0.0	0.016	0.002	8.00	7.10	360.00	20.67	1.13	0.21	0.211
1.00	0.50	0.0	139.3	0.068	0.000	67.50	60.50	420.50	24.15	1.12	0.00	0.434
1.00	0.55	33.6	0.0	0.016	0.001	13.00	5.50	426.00	24.46	2.36	0.09	0.163
1.00	0.60	0.0	139.4	0.068	0.001	80.00	45.00	471.00	27.05	1.78	0.02	0.323
1.00	0.45	33.6	0.0	0.016	0.001	11.50	3.00	474.00	27.22	3.83	0.33	0.089
1.00	0.50	0.0	139.3	0.068	0.001	88.00	40.00	514.00	29.52	2.20	0.01	0.287
1.00	0.55	33.6	0.0	0.016	0.002	14.00	4.50	518.50	29.78	3.11	0.33	0.134
1.00	0.50	0.0	139.3	0.068	0.003	99.00	33.50	552.00	31.70	2.96	0.09	0.240
1.00	0.45	33.6	0.0	0.016	0.000	11.00	2.00	554.00	31.81	5.50	0.10	0.059
1.00	0.40	0.0	139.4	0.068	0.008	105.00	19.00	573.00	32.91	5.53	0.45	0.136
1.00	0.45	33.6	0.0	0.016	0.003	12.00	2.50	575.50	33.05	4.80	1.20	0.074

TABLE A 6 (CONTINUED)

RESULTS OF RUN GTD 6
[0.20 HCPV CO2 @ 1.0 MPa (0.151 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

Porosity [%] = 42.1
Oil Viscosity [mPa.s] = 1175.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.03

Pore Volume [cm3] = 2050.0
Initial Oil Saturation [%] = 84.9
Hydrocarbon Pore Volume [cm3] = 1741.3
Carbon Dioxide Retention [%inj] = 53.96

Connate Water Saturation [%] = 15.1
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 14.5200
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	0.55	0.0	139.3	0.068	0.027	112.00	20.00	595.50	34.20	5.60	1.34	0.144
1.00	0.40	33.6	0.0	0.016	0.009	18.00	2.00	597.50	34.31	9.00	4.50	0.059
1.00	0.55	0.0	139.6	0.068	0.064	100.00	24.00	621.50	35.69	4.17	2.69	0.172
1.00	0.55	0.0	140.5	0.069	0.091	122.00	14.50	636.00	36.52	8.41	6.28	0.103
1.00	0.55	0.0	231.0	0.113	0.173	201.00	33.00	669.00	38.42	6.09	5.23	0.143
1.00	0.45	0.0	229.2	0.112	0.179	203.00	26.00	695.00	39.91	7.81	6.88	0.113
1.00	0.45	0.0	213.9	0.104	0.173	199.00	17.00	712.00	40.89	11.71	10.15	0.079
1.00	0.45	0.0	239.2	0.117	0.158	221.00	19.00	731.00	41.98	11.63	8.32	0.079
1.00	0.50	0.0	251.6	0.123	0.144	242.00	13.00	744.00	42.73	18.62	11.08	0.052
1.00	0.50	0.0	218.1	0.106	0.101	218.00	15.50	759.50	43.62	14.06	6.52	0.071
1.00	0.50	0.0	473.3	0.231	0.121	444.00	35.00	794.50	45.63	12.69	3.46	0.074
1.00	0.50	0.0	491.9	0.240	0.118	467.00	30.00	824.50	47.35	15.57	3.93	0.061
1.00	0.50	0.0	459.7	0.224	0.104	441.00	22.00	846.50	48.61	20.05	4.70	0.048
1.00	0.50	0.0	160.4	0.078	0.016	159.00	5.00	851.50	48.90	31.80	3.10	0.031
0.10	0.10	0.0	0.0	0.000	0.160	48.00	42.00	893.50	51.31	1.14	3.81	

TABLE A 7

RESULTS OF RUN LC 7
[0.30 HCPV CO2 @ 1.0 MPa (0.219 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

Porosity [%] = 38.0
Oil Viscosity [mPa.s] = 1279.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 7.20

Pore Volume [cm3] = 1850.0
Initial Oil Saturation [%] = 91.1
Hydrocarbon Pore Volume [cm3] = 1684.4
Carbon Dioxide Retention [%inj] = -4.04

Connate Water Saturation [%] = 8.9
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 15.3600
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	0.80	53.8	0.0	0.029	0.000	0.00	0.01	0.01	0.00	0.10	0.00	0.000
1.00	0.75	0.0	202.8	0.110	0.000	10.00	197.90	197.91	11.75	0.05	0.00	0.976
1.00	0.70	50.5	0.0	0.027	0.000	2.50	32.50	230.41	13.68	0.08	0.00	0.644
1.00	0.60	0.0	202.1	0.109	0.034	52.00	115.00	345.41	20.51	0.45	0.30	0.569
1.00	0.70	50.5	0.0	0.027	0.000	12.00	10.50	355.91	21.13	1.14	0.00	0.208
1.00	0.75	0.0	202.1	0.109	0.089	113.00	72.00	427.91	25.41	1.57	1.24	0.356
1.00	0.60	50.5	0.0	0.027	0.038	23.00	6.00	433.91	25.76	3.83	6.33	0.119
1.00	0.70	0.0	202.1	0.109	0.256	133.00	44.50	478.41	28.40	2.99	5.75	0.220
1.00	0.65	50.5	0.0	0.027	0.036	20.00	4.50	482.91	28.67	4.44	7.89	0.089
1.00	0.60	0.0	202.1	0.109	0.452	141.00	45.00	527.91	31.34	3.13	10.04	0.223
1.00	0.45	50.5	0.0	0.027	0.042	22.50	1.50	529.41	31.43	15.00	28.00	0.030
1.00	0.70	0.0	202.1	0.109	0.330	146.00	29.50	558.91	33.18	4.95	11.19	0.146
1.00	0.55	50.9	0.0	0.028	0.104	38.50	4.00	562.91	33.42	9.63	26.00	0.079
1.00	0.50	0.0	202.2	0.109	0.417	130.00	35.50	598.41	35.53	3.66	11.75	0.176
1.00	0.55	50.5	0.0	0.027	0.033	30.50	3.00	601.41	35.71	10.17	11.00	0.059
1.00	0.60	0.0	202.1	0.109	0.626	150.00	26.00	627.41	37.25	5.77	24.08	0.129
1.00	0.65	50.5	0.0	0.027	0.087	26.75	1.75	629.16	37.35	15.29	49.71	0.035

TABLE A 7 (CONTINUED)

RESULTS OF RUN LC 7
[0.30 HCPV CO2 @ 1.0 MPa (0.219 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

Porosity [%] = 38.0
Oil Viscosity [mPa.s] = 1279.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 7.20

Pore Volume [cm3] = 1850.0
Initial Oil Saturation [%] = 91.1
Hydrocarbon Pore Volume [cm3] = 1684.4
Carbon Dioxide Retention [%inj] = -4.04

Connate Water Saturation [%] = 8.9
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 15.3600
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	0.55	0.0	196.1	0.106	0.541	152.50	12.50	641.66	38.10	12.20	43.28	0.064
1.00	0.50	50.5	0.0	0.027	0.108	28.90	1.85	643.51	38.21	15.62	58.38	0.037
1.00	0.60	0.0	202.2	0.109	0.916	161.00	22.50	666.01	39.54	7.16	40.71	0.111
1.00	0.64	0.0	211.2	0.114	0.625	190.50	17.50	683.51	40.58	10.89	35.71	0.083
0.10	0.10	0.0	0.0	0.000	0.771	95.00	51.00	734.51	43.61	1.86	15.12	

TABLE A 8

RESULTS OF RUN LC 8

[0.10 HCPV CO2 @ 1.0 MPa (0.071 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

Porosity [%] = 38.0
Oil Viscosity [mPa.s] = 1046.1
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 2.95
Pore Volume [cm3] = 1850.0
Initial Oil Saturation [%] = 88.9
Hydrocarbon Pore Volume [cm3] = 1643.8
Carbon Dioxide Retention [%inj] = 15.02
Connate Water Saturation [%] = 11.1
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 15.3600
Average Flow Velocity [m/d] = 1.290

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	0.85	16.4	0.0	0.009	0.000	0.00	22.75	22.75	1.38	0.00	0.00	1.384
1.00	0.95	0.0	65.1	0.035	0.000	0.00	50.00	72.75	4.43	0.00	0.00	0.768
1.00	0.88	16.4	0.0	0.009	0.000	0.00	16.10	88.85	5.41	0.00	0.00	0.979
1.10	0.90	0.0	65.7	0.036	0.000	0.00	54.90	143.75	8.75	0.00	0.00	0.835
1.00	0.90	16.4	0.0	0.009	0.002	3.00	15.20	158.95	9.67	0.20	0.10	0.925
1.00	0.95	0.0	65.8	0.036	0.003	7.00	5.10	164.05	9.98	1.37	0.59	0.078
1.20	0.95	16.4	0.0	0.009	0.002	6.10	7.90	171.95	10.46	0.77	0.19	0.481
1.00	0.85	0.0	65.9	0.036	0.001	20.50	25.40	197.35	12.01	0.81	0.02	0.385
1.10	0.85	16.4	0.0	0.009	0.000	11.80	10.30	207.65	12.63	1.15	0.00	0.627
1.00	0.90	0.0	65.8	0.036	0.001	30.50	16.50	224.15	13.64	1.85	0.06	0.251
1.00	0.80	16.4	0.0	0.009	0.001	10.20	5.10	229.25	13.95	2.00	0.20	0.310
1.00	0.90	0.0	66.0	0.036	0.000	23.50	32.60	261.85	15.93	0.72	0.00	0.494
1.00	0.90	18.5	0.0	0.010	0.001	13.70	4.70	266.55	16.22	2.91	0.11	0.255
1.00	0.90	0.0	65.8	0.036	0.002	27.50	24.50	291.05	17.71	1.12	0.08	0.372
1.00	0.90	16.4	0.0	0.009	0.000	21.10	7.00	298.05	18.13	3.01	0.00	0.426
1.00	0.95	0.0	66.4	0.036	0.001	41.50	44.50	342.55	20.84	0.93	0.02	0.670
1.00	0.85	16.4	0.0	0.009	0.001	0.50	1.50	344.05	20.93	0.33	0.67	0.091

TABLE A 8 (CONTINUED)

RESULTS OF RUN LC 8
[0.10 HCPV CO2 @ 1.0 MPa (0.071 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

Porosity [%] = 38.0
Oil Viscosity [mPa.s] = 1046.1
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 2.95

Pore Volume [cm3] = 1850.0
Initial Oil Saturation [%] = 88.9
Hydrocarbon Pore Volume [cm3] = 1643.8
Carbon Dioxide Retention [%inj] = 15.02

Connate Water Saturation [%] = 11.1
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 15.3600
Average Flow Velocity [m/d] = 1.290

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.20	0.95	0.0	65.8	0.036	0.072	16.10	3.70	347.75	21.16	4.35	19.59	0.056
1.00	0.90	16.4	0.0	0.009	0.019	13.10	4.10	351.85	21.41	3.20	4.63	0.249
1.10	0.90	0.0	65.9	0.036	0.052	41.00	10.50	362.35	22.04	3.90	4.95	0.159
1.00	0.80	0.0	214.9	0.116	0.297	173.00	53.00	415.35	25.27	3.26	5.60	0.247
1.10	0.95	0.0	240.0	0.130	0.287	194.50	39.30	454.65	27.66	4.95	7.30	0.164
1.00	0.90	0.0	244.7	0.132	0.267	214.00	30.00	484.65	29.48	7.13	8.90	0.123
1.20	0.85	0.0	244.5	0.132	0.205	224.50	21.50	506.15	30.79	10.44	9.53	0.088
1.00	0.90	0.0	245.8	0.133	0.108	230.00	16.10	522.25	31.77	14.29	6.71	0.066
1.00	0.90	0.0	265.3	0.143	0.044	253.00	17.00	539.25	32.81	14.88	2.59	0.064
1.00	0.90	0.0	131.2	0.098	0.118	177.00	8.75	548.00	33.34	20.23	13.49	0.048
1.00	0.90	0.0	252.0	0.136	0.009	236.50	10.00	558.00	33.95	23.65	0.90	0.040
1.00	0.95	0.0	86.4	0.047	0.008	79.50	3.50	561.50	34.16	22.71	2.43	0.040
1.00	0.85	0.0	492.8	0.266	0.004	465.00	27.82	589.32	35.85	16.71	0.14	0.056
0.10	0.10	0.0	0.0	0.000	0.014	51.00	16.00	605.32	36.83	3.19	0.87	

TABLE A 9

RESULTS OF RUN GTD 9
[0.20 HCPV CO2 @ 1.0 MPa (0.154 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

Porosity [%] = 37.9
Oil Viscosity [mPa.s] = 1046.1
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.05
Pore Volume [cm3] = 1850.0
Initial Oil Saturation [%] = 95.8
Hydrocarbon Pore Volume [cm3] = 1772.3
Carbon Dioxide Retention [%inj] = 37.96
Connate Water Saturation [%] = 4.2
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 14.6000
Average Flow Velocity [m/d] = 1.290

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	0.85	31.9	0.0	0.017	0.000	0.00	23.95	23.95	1.35	0.00	0.00	0.751
1.00	0.85	0.0	142.0	0.077	0.000	0.00	125.00	148.95	8.40	0.00	0.00	0.880
1.00	0.90	31.9	0.0	0.017	0.000	0.00	25.50	174.45	9.84	0.00	0.00	0.799
1.00	0.95	0.0	141.8	0.077	0.000	17.00	105.00	279.45	15.77	0.16	0.00	0.740
1.00	0.85	32.7	0.0	0.018	0.000	11.20	13.90	293.35	16.55	0.81	0.00	0.425
1.00	0.90	0.0	141.8	0.077	0.000	57.25	58.95	352.30	19.88	0.97	0.00	0.416
1.00	0.94	31.9	0.0	0.017	0.000	20.75	7.35	359.65	20.29	2.82	0.00	0.230
1.00	0.90	0.0	141.8	0.077	0.000	87.50	33.00	392.65	22.15	2.65	0.00	0.233
1.00	0.85	31.9	0.0	0.017	0.000	20.40	6.10	398.75	22.50	3.34	0.00	0.191
1.00	0.90	0.0	141.8	0.077	0.000	83.50	50.50	449.25	25.35	1.65	0.00	0.356
1.00	0.85	31.9	0.0	0.017	0.000	16.00	5.00	454.25	25.63	3.20	0.00	0.157
1.00	0.95	0.0	141.8	0.077	0.000	74.50	34.50	488.75	27.58	2.16	0.00	0.243
1.00	0.65	31.9	0.0	0.017	0.001	26.00	8.00	496.75	28.03	3.25	0.06	0.251
1.00	0.70	0.0	142.3	0.077	0.014	109.75	30.45	527.20	29.75	3.60	0.46	0.214
1.00	0.75	31.9	0.0	0.017	0.003	13.90	0.85	528.05	29.79	16.35	3.53	0.027
1.00	0.80	0.0	148.5	0.080	0.021	94.50	18.00	546.05	30.81	5.25	1.19	0.121
1.00	0.85	31.9	0.0	0.017	0.016	33.00	6.90	552.95	31.20	4.78	2.32	0.216

TABLE A 9 (CONTINUED)

RESULTS OF RUN GTD 9
[0.20 HCPV CO2 @ 1.0 MPa (0.154 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

Porosity [%] = 37.9
Oil Viscosity [mPa.s] = 1046.1
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.05

Pore Volume [cm3] = 1850.0
Initial Oil Saturation [%] = 95.8
Hydrocarbon Pore Volume [cm3] = 1772.3
Carbon Dioxide Retention [%inj] = 37.96

Connate Water Saturation [%] = 4.2
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 14.6000
Average Flow Velocity [m/d] = 1.290

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	0.85	0.0	141.7	0.077	0.069	101.00	15.00	567.95	32.05	6.73	4.60	0.106
1.00	0.80	31.9	0.0	0.017	0.019	27.00	3.50	571.45	32.24	7.71	5.29	0.110
1.00	0.75	0.0	141.8	0.077	0.095	88.00	24.20	595.65	33.61	3.64	3.90	0.171
1.00	0.80	0.0	117.7	0.064	0.150	91.00	29.00	624.65	35.25	3.14	5.17	0.246
1.00	0.85	0.0	229.7	0.124	0.368	195.00	51.20	675.85	38.13	3.81	7.18	0.223
1.00	0.65	0.0	264.1	0.143	0.414	216.00	26.00	701.85	39.60	8.31	15.90	0.098
1.00	0.75	0.0	243.6	0.132	0.253	206.50	21.60	723.45	40.82	9.56	11.74	0.089
1.00	0.78	0.0	251.0	0.136	0.151	227.00	21.00	744.45	42.00	10.81	7.19	0.084
1.00	0.85	0.0	95.8	0.052	0.038	88.00	9.00	753.45	42.51	9.78	4.22	0.094
1.00	0.86	0.0	98.9	0.053	0.029	93.50	10.50	763.95	43.10	8.90	2.76	0.106
0.10	0.10	0.0	0.0	0.000	0.425	104.00	58.00	821.95	46.38	1.79	7.33	

TABLE A10

RESULTS OF RUN GTD 10
[0.30 HCPV CO2 @ 1.0 MPa (0.229 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

Porosity [%] = 29.5
Oil Viscosity [mPa.s] = 1046.1
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 6.13

Pore Volume [cm3] = 1925.0
Initial Oil Saturation [%] = 91.7
Hydrocarbon Pore Volume [cm3] = 1764.4
Carbon Dioxide Retention [%inj] = 12.31

Connate Water Saturation [%] = 8.3
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 12.1000
Average Flow Velocity [m/d] = 1.290

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	0.90	45.9	0.0	0.024	0.000	0.00	21.90	21.90	1.24	0.00	0.00	0.477
1.00	0.85	0.0	211.7	0.110	0.000	1.50	196.40	218.30	12.37	0.01	0.00	0.928
1.00	0.88	45.9	0.0	0.024	0.000	6.90	21.10	239.40	13.57	0.33	0.00	0.460
1.00	0.90	0.0	211.7	0.110	0.000	89.90	104.10	343.50	19.47	0.86	0.00	0.492
1.00	0.75	45.9	0.0	0.024	0.000	19.00	5.20	348.70	19.76	3.65	0.00	0.113
1.00	0.80	0.0	211.7	0.110	0.000	128.00	62.50	411.20	23.31	2.05	0.00	0.295
1.00	0.90	45.9	0.0	0.024	0.000	26.00	5.60	416.80	23.62	4.64	0.00	0.122
1.00	0.95	0.0	211.8	0.110	0.000	144.00	44.00	460.80	26.12	3.27	0.00	0.208
1.00	0.85	45.9	0.0	0.024	0.000	21.00	3.00	463.80	26.29	7.00	0.00	0.065
1.00	0.85	0.0	211.7	0.110	0.004	175.00	29.00	492.80	27.93	6.03	0.14	0.137
1.00	0.90	45.9	0.0	0.024	0.001	24.00	1.20	494.00	28.00	20.00	0.42	0.026
1.00	0.85	0.0	211.7	0.110	0.014	161.50	22.00	516.00	29.25	7.34	0.64	0.104
1.00	0.90	45.9	0.0	0.024	0.007	29.90	2.90	518.90	29.41	10.31	2.41	0.063
1.00	0.80	0.0	211.8	0.110	0.071	160.50	23.00	541.90	30.71	6.98	3.07	0.109
1.00	0.90	45.9	0.0	0.024	0.028	35.00	2.50	544.40	30.85	14.00	11.20	0.054
1.00	0.80	0.0	211.8	0.110	0.150	160.00	23.00	567.40	32.16	6.96	6.50	0.109
1.00	0.80	45.9	0.0	0.024	0.033	30.50	4.30	571.70	32.40	7.09	7.72	0.094

TABLE A10 (CONTINUED)

RESULTS OF RUN GTD 10

[0.30 HCPV CO2 @ 1.0 MPa (0.229 g-mol) 4:1 WAG, 10-Slugs, 2D Model]

Porosity [%] = 29.5
Oil Viscosity [mPa.s] = 1046.1
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 6.13

Pore Volume [cm3] = 1925.0
Initial Oil Saturation [%] = 91.7
Hydrocarbon Pore Volume [cm3] = 1764.4
Carbon Dioxide Retention [%inj] = 12.31

Connate Water Saturation [%] = 8.3
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 12.1000
Average Flow Velocity [m/d] = 1.290

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	0.90	0.0	213.5	0.111	0.155	165.00	23.00	594.70	33.71	7.17	6.74	0.108
1.00	0.80	45.9	0.0	0.024	0.091	56.50	4.50	599.20	33.96	12.56	20.22	0.098
1.00	0.90	0.0	211.8	0.110	0.306	126.50	16.50	615.70	34.90	7.67	18.55	0.078
1.00	0.90	0.0	247.4	0.129	0.394	230.00	22.00	637.70	36.14	10.45	17.91	0.089
1.00	0.85	0.0	195.9	0.102	0.205	172.50	25.50	663.20	37.59	6.76	8.02	0.130
1.00	0.90	0.0	275.5	0.143	0.621	256.00	22.00	685.20	38.83	11.64	28.23	0.080
1.00	0.85	0.0	244.7	0.127	0.581	226.00	22.00	707.20	40.08	10.27	26.41	0.090
1.00	0.90	0.0	252.9	0.131	0.355	240.00	10.00	717.20	40.65	24.00	35.50	0.040
1.00	0.90	0.0	494.6	0.257	0.399	475.50	15.50	732.70	41.53	30.68	25.71	0.031
0.10	0.10	0.0	0.0	0.000	0.775	124.00	46.00	778.70	44.13	2.70	16.85	

TABLE A30

RESULTS OF RUN LC30
[0.89 HCPV CO2 @ 2.5 MPa (1.13 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 37.6
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 47.55

Pore Volume [cm3] = 1170.0
Initial Oil Saturation [%] = 90.2
Hydrocarbon Pore Volume [cm3] = 1055.8
Carbon Dioxide Retention [%inj] = 16.76

Connate Water Saturation [%] = 9.8
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 11.3500
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.50	2.40	94.5	0.0	0.081	0.000	0.00	7.00	7.00	0.66	0.00	0.00	0.074
2.64	2.45	0.0	375.9	0.321	1.383	115.00	238.00	245.00	23.21	0.48	5.81	0.633
2.50	2.40	94.5	0.0	0.081	0.000	30.00	13.00	258.00	24.44	2.31	0.00	0.138
2.45	2.20	0.0	375.8	0.321	0.662	275.00	65.00	323.00	30.59	4.23	10.18	0.173
2.20	2.10	94.5	0.0	0.081	0.125	33.00	7.00	330.00	31.26	4.71	17.86	0.074
2.45	2.30	0.0	375.9	0.321	1.445	308.00	37.00	367.00	34.76	8.32	39.05	0.098
2.20	2.10	96.9	0.0	0.083	0.134	35.00	5.00	372.00	35.23	7.00	26.80	0.052
2.40	2.28	0.0	375.9	0.321	1.204	320.00	20.00	392.00	37.13	16.00	60.20	0.053
2.22	2.12	95.7	0.0	0.082	0.000	52.00	6.00	398.00	37.70	8.67	0.00	0.063
2.52	2.42	0.0	375.9	0.321	1.510	343.00	22.00	420.00	39.78	15.59	68.64	0.059
2.30	2.30	94.4	0.0	0.081	0.102	49.00	5.00	425.00	40.25	9.80	20.40	0.053
2.40	2.40	0.0	376.6	0.322	1.567	316.00	20.00	445.00	42.15	15.80	78.35	0.053
2.10	2.00	106.6	0.0	0.091	0.214	44.00	4.00	449.00	42.53	11.00	53.50	0.038
2.50	2.40	0.0	375.8	0.321	1.823	312.00	18.00	467.00	44.23	17.33	101.28	0.048
2.00	1.50	94.4	0.0	0.081	0.571	58.00	4.00	471.00	44.61	14.50	142.75	0.042
2.60	2.40	0.0	375.9	0.321	1.574	309.00	9.00	480.00	45.46	34.33	174.89	0.024
2.50	2.40	95.7	0.0	0.082	2.948	28.00	2.00	482.00	45.65	14.00	1474.00	0.021

TABLE A30 (CONTINUED)

RESULTS OF RUN LC30
[0.89 HCPV CO2 @ 2.5 MPa (1.13 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 37.6
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 47.55

Pore Volume [cm3] = 1170.0
Initial Oil Saturation [%] = 90.2
Hydrocarbon Pore Volume [cm3] = 1055.8
Carbon Dioxide Retention [%inj] = 16.76

Connate Water Saturation [%] = 9.8
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 11.3500
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.36	2.30	0.0	376.9	0.322	1.383	228.00	4.00	486.00	46.03	57.00	345.75	0.011
2.50	2.48	94.4	0.0	0.081	0.135	37.00	2.00	488.00	46.22	18.50	67.50	0.021
2.50	2.20	0.0	375.9	0.321	0.713	336.00	10.00	498.00	47.17	33.60	71.30	0.027
0.10	0.10	0.0	0.0	0.000	3.484	220.00	32.00	530.00	50.20	6.88	108.88	

TABLE A31

RESULTS OF RUN LC31
[0.20 HCPV CO2 @ 2.5 MPa (0.22 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 36.4
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 10.29

Pore Volume [cm3] = 1130.0
Initial Oil Saturation [%] = 79.4
Hydrocarbon Pore Volume [cm3] = 896.0
Carbon Dioxide Retention [%inj] = 21.05

Connate Water Saturation [%] = 20.6
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 11.0400
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.41	2.40	18.2	0.0	0.016	0.000	3.50	2.50	2.50	0.28	1.40	0.00	0.138
2.50	2.40	0.0	71.8	0.063	0.000	0.00	65.90	68.40	7.63	0.00	0.00	0.918
2.44	2.43	18.2	0.0	0.016	0.000	0.00	10.90	79.30	8.85	0.00	0.00	0.600
2.50	2.40	0.0	73.3	0.065	0.000	0.00	66.20	145.50	16.24	0.00	0.00	0.904
2.47	2.26	20.6	0.0	0.018	0.000	0.00	7.10	152.60	17.03	0.00	0.00	0.345
2.48	2.36	0.0	71.7	0.063	0.000	19.50	52.50	205.10	22.89	0.37	0.00	0.732
2.82	1.87	19.4	0.0	0.017	0.000	3.60	6.20	211.30	23.58	0.58	0.00	0.320
2.30	2.40	0.0	71.7	0.063	0.000	36.60	28.20	239.50	26.73	1.30	0.00	0.393
2.50	2.40	18.2	0.0	0.016	0.000	10.20	6.80	246.30	27.49	1.50	0.00	0.374
2.40	2.20	0.0	71.7	0.063	0.000	39.00	21.00	267.30	29.83	1.86	0.00	0.293
2.40	2.20	18.2	0.0	0.016	0.000	13.40	6.80	274.10	30.59	1.97	0.00	0.374
2.60	2.50	0.0	71.7	0.063	0.000	42.00	14.50	288.60	32.21	2.90	0.00	0.202
2.44	2.50	18.2	0.0	0.016	0.000	9.80	4.20	292.80	32.68	2.33	0.00	0.231
2.43	2.60	0.0	71.8	0.064	0.023	48.00	14.50	307.30	34.30	3.31	1.59	0.202
2.40	2.52	18.2	0.0	0.016	0.005	11.40	3.80	311.10	34.72	3.00	1.32	0.209
2.32	2.46	0.0	71.7	0.063	0.017	50.10	12.90	324.00	36.16	3.88	1.32	0.180
2.48	2.44	18.2	0.0	0.016	0.005	11.60	3.60	327.60	36.56	3.22	1.39	0.198

TABLE A31 (CONTINUED)

RESULTS OF RUN LC31
[0.20 HCPV CO2 @ 2.5 MPa (0.22 g-mol) 4:1 WAG. 10-Slugs]

Porosity [%] = 36.4
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 10.29

Pore Volume [cm3] = 1130.0
Initial Oil Saturation [%] = 79.4
Hydrocarbon Pore Volume [cm3] = 896.0
Carbon Dioxide Retention [%inj] = 21.05

Connate Water Saturation [%] = 20.6
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 11.0400
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.25	2.30	0.0	72.3	0.064	0.095	50.20	11.00	338.60	37.79	4.56	8.64	0.152
2.22	2.30	18.2	0.0	0.016	0.005	15.10	3.30	341.90	38.16	4.58	1.52	0.182
2.38	2.50	0.0	71.6	0.063	0.000	49.00	10.70	352.60	39.35	4.58	0.00	0.149
2.45	2.50	0.0	115.8	0.103	0.000	96.00	19.00	371.60	41.47	5.05	0.00	0.164
2.32	2.50	0.0	137.9	0.122	0.695	121.70	16.30	387.90	43.29	7.47	42.64	0.118
2.30	2.46	0.0	488.1	0.432	1.335	452.00	36.00	423.90	47.31	12.56	37.08	0.074
2.35	2.48	0.0	491.4	0.435	0.669	466.00	28.00	451.90	50.44	16.64	23.89	0.057
2.30	2.52	0.0	235.7	0.209	0.233	224.50	11.50	463.40	51.72	19.52	20.26	0.049
2.40	2.48	0.0	250.9	0.222	0.299	238.00	14.50	477.90	53.34	16.41	20.62	0.058
2.38	2.44	0.0	245.7	0.217	0.304	238.00	9.00	486.90	54.34	26.44	33.78	0.037
2.40	2.46	0.0	223.1	0.197	0.265	217.00	8.00	494.90	55.23	27.13	33.12	0.036
2.40	2.55	0.0	385.6	0.341	0.199	380.00	11.00	505.90	56.46	34.55	18.09	0.029
0.10	0.10	0.0	0.0	0.000	0.002	10.00	5.00	510.90	57.02	2.00	0.40	

TABLE A32

RESULTS OF RUN LC32
[0.40 HCPV CO2 @ 2.5 MPa (0.53 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 37.6
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 27.68

Pore Volume [cm3] = 1170.0
Initial Oil Saturation [%] = 93.7
Hydrocarbon Pore Volume [cm3] = 1095.8
Carbon Dioxide Retention [%inj] = 25.04

Connate Water Saturation [%] = 6.3
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 14.1300
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.30	2.50	43.6	0.0	0.037	0.000	0.00	0.10	0.10	0.01	0.00	0.00	0.002
2.58	2.50	0.0	175.4	0.150	0.109	24.00	139.90	140.00	12.78	0.17	0.78	0.798
2.46	2.50	46.0	0.0	0.039	0.000	8.50	8.75	148.75	13.57	0.97	0.00	0.190
2.48	2.50	0.0	175.3	0.150	0.164	119.00	46.00	194.75	17.77	2.59	3.57	0.262
2.40	2.40	43.6	0.0	0.037	0.000	19.25	6.00	200.75	18.32	3.21	0.00	0.138
2.50	2.56	0.0	175.3	0.150	0.100	127.50	25.50	226.25	20.65	5.00	3.92	0.145
2.53	2.51	43.6	0.0	0.037	0.000	24.00	5.75	232.00	21.17	4.17	0.00	0.132
2.48	2.50	0.0	175.5	0.150	0.561	122.00	31.00	263.00	24.00	3.94	18.10	0.177
2.43	2.52	43.6	0.0	0.037	0.114	22.75	5.15	268.15	24.47	4.42	22.14	0.118
2.43	2.53	0.0	175.3	0.150	1.162	126.50	22.00	290.15	26.48	5.75	52.82	0.125
2.50	2.54	43.6	0.0	0.037	0.004	29.40	5.70	295.85	27.00	5.16	0.70	0.131
2.50	2.51	0.0	187.3	0.160	0.889	135.00	18.00	313.85	28.64	7.50	49.39	0.096
2.48	2.52	43.6	0.0	0.037	0.010	30.20	4.70	318.55	29.07	6.43	2.13	0.108
2.52	2.50	0.0	175.4	0.150	0.575	130.50	14.00	332.55	30.35	9.32	41.07	0.080
2.48	2.51	44.8	0.0	0.038	0.021	30.10	3.70	336.25	30.69	8.14	5.68	0.083
2.47	2.53	0.0	175.4	0.150	0.670	132.00	13.50	349.75	31.92	9.78	49.63	0.077
2.46	2.52	43.6	0.0	0.037	0.063	30.80	4.30	354.05	32.31	7.16	14.65	0.099

TABLE A32 (CONTINUED)

RESULTS OF RUN LC32
[0.40 HCPV CO2 @ 2.5 MPa (0.53 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 37.6
Oil Viscosity [mPa.s] = 1055.3
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 27.68

Pore Volume [cm3] = 1170.0
Initial Oil Saturation [%] = 93.7
Hydrocarbon Pore Volume [cm3] = 1095.8
Carbon Dioxide Retention [%inj] = 25.04

Connate Water Saturation [%] = 6.3
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 14.1300
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.50	2.53	0.0	175.4	0.150	0.786	130.50	14.50	368.55	33.63	9.00	54.21	0.083
2.46	2.55	46.0	0.0	0.039	0.053	13.90	3.50	372.05	33.95	3.97	15.14	0.076
2.42	2.56	0.0	175.4	0.150	1.041	132.00	13.50	385.55	35.18	9.78	77.11	0.077
2.50	2.53	0.0	468.2	0.400	1.851	437.00	31.00	416.55	38.01	14.10	59.71	0.066
2.50	2.52	0.0	492.4	0.421	0.996	476.00	18.50	435.05	39.70	25.73	53.84	0.038
0.10	0.10	0.0	0.0	0.000	0.181	92.60	15.60	450.65	41.13	5.94	11.60	

TABLE A33

RESULTS OF RUN LC33
[0.20 HCPV CO2 @ 2.5 MPa (0.22 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 37.4
Oil Viscosity [mPa.s] = 1230.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 11.13

Pore Volume [cm3] = 1164.0
Initial Oil Saturation [%] = 94.9
Hydrocarbon Pore Volume [cm3] = 1105.1
Carbon Dioxide Retention [%inj] = 12.42

Connate Water Saturation [%] = 5.1
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 13.0800
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.50	1.50	21.8	0.0	0.019	0.000	0.10	0.10	0.10	0.01	1.00	0.00	0.005
3.00	2.50	0.0	88.4	0.076	0.099	1.00	101.00	101.10	9.15	0.01	0.98	1.142
2.50	2.50	23.0	0.0	0.020	0.000	1.00	16.50	117.60	10.64	0.06	0.00	0.718
2.50	2.50	0.0	88.4	0.076	0.033	20.20	58.30	175.90	15.92	0.35	0.57	0.660
2.50	2.40	21.8	0.0	0.019	0.000	8.90	12.10	188.00	17.01	0.74	0.00	0.556
2.54	2.50	0.0	118.5	0.102	0.050	42.00	65.50	253.50	22.94	0.64	0.76	0.553
2.50	2.48	21.8	0.0	0.019	0.000	12.10	5.40	258.90	23.43	2.24	0.00	0.248
2.50	2.50	0.0	88.5	0.076	0.217	50.00	25.00	283.90	25.69	2.00	8.68	0.282
2.46	2.42	21.8	0.0	0.019	0.111	14.00	3.50	287.40	26.01	4.00	31.71	0.161
2.50	2.50	0.0	89.0	0.076	0.210	56.00	24.00	311.40	28.18	2.33	8.75	0.270
2.50	2.48	21.8	0.0	0.019	0.025	13.90	3.35	314.75	28.48	4.15	7.46	0.154
2.50	2.50	0.0	87.8	0.075	0.077	56.00	13.00	327.75	29.66	4.31	5.92	0.148
2.50	2.50	21.8	0.0	0.019	0.125	15.00	3.00	330.75	29.93	5.00	41.67	0.138
2.50	2.50	0.0	88.4	0.076	0.341	55.50	13.50	344.25	31.15	4.11	25.26	0.153
2.40	2.40	21.8	0.0	0.019	0.080	16.00	2.50	346.75	31.38	6.40	32.00	0.115
2.50	2.50	0.0	88.4	0.076	0.000	59.00	14.50	361.25	32.69	4.07	0.00	0.164
2.50	2.48	21.8	0.0	0.019	0.053	15.10	3.15	364.40	32.98	4.79	16.83	0.145

TABLE A33 (CONTINUED)

RESULTS OF RUN LC33
[0.20 HCPV CO2 @ 2.5 MPa (0.22 g-mol) 4:1 WAG, 10-Slugs]

Porosity [%] = 37.4
Oil Viscosity [mPa.s] = 1230.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 11.13

Pore Volume [cm3] = 1164.0
Initial Oil Saturation [%] = 94.9
Hydrocarbon Pore Volume [cm3] = 1105.1
Carbon Dioxide Retention [%inj] = 12.42

Connate Water Saturation [%] = 5.1
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 13.0800
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.50	2.50	0.0	88.4	0.076	0.190	59.50	14.50	378.90	34.29	4.10	13.10	0.164
2.50	2.50	21.8	0.0	0.019	0.094	15.50	2.50	381.40	34.51	6.20	37.60	0.115
2.50	2.45	0.0	88.4	0.076	0.343	56.00	15.25	396.65	35.89	3.67	22.49	0.172
2.50	2.50	0.0	250.0	0.215	0.932	218.00	29.00	425.65	38.52	7.52	32.14	0.116
2.50	2.50	0.0	476.4	0.409	1.192	430.00	51.00	476.65	43.13	8.43	23.37	0.107
2.50	2.45	0.0	466.9	0.401	0.629	445.00	25.00	501.65	45.40	17.80	25.16	0.054
2.52	2.50	0.0	479.8	0.412	0.280	460.00	25.00	526.65	47.66	18.40	11.20	0.052
2.50	2.50	0.0	459.1	0.394	0.237	450.50	11.50	538.15	48.70	39.17	20.61	0.025
2.50	2.50	0.0	342.7	0.294	0.190	335.00	10.00	548.15	49.60	33.50	19.00	0.029
0.10	0.10	0.0	0.0	0.000	0.000	56.00	17.00	565.15	51.14	3.29	0.00	

TABLE A34

RESULTS OF RUN LC34
[2.02 HCPV WF=>0.20 RHCPV CO2 @ 2.5MPa (0.24g-mol) 4:1 WAG,10 Slugs]

Porosity [%] = 36.5
Oil Viscosity [mPa.s] = 882.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.46

Pore Volume [cm3] = 1134.0
Initial Oil Saturation [%] = 92.5
Hydrocarbon Pore Volume [cm3] = 1049.4
Carbon Dioxide Retention [%inj] = 36.91

Connate Water Saturation [%] = 7.5
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 9.9100
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.50	2.40	0.0	364.6	0.322	0.000	119.00	250.00	250.00	23.82	0.48	0.00	0.686
2.50	2.40	0.0	462.6	0.408	0.000	385.00	83.00	333.00	31.73	4.64	0.00	0.179
2.50	2.40	0.0	445.4	0.393	0.000	403.00	45.00	378.00	36.02	8.96	0.00	0.101
2.50	2.40	0.0	470.1	0.415	0.000	439.00	38.00	416.00	39.64	11.55	0.00	0.081
2.50	2.35	0.0	380.5	0.336	0.000	367.00	19.00	435.00	41.45	19.32	0.00	0.050
2.50	2.40	12.1	0.0	0.011	0.000	13.70	0.50	435.50	41.50	27.40	0.00	0.041
2.50	2.40	0.0	49.1	0.043	0.000	43.00	3.50	439.00	41.83	12.29	0.00	0.071
2.40	2.30	12.1	0.0	0.011	0.000	12.75	1.00	440.00	41.93	12.75	0.00	0.083
2.50	2.40	0.0	49.2	0.043	0.000	32.00	4.00	444.00	42.31	8.00	0.00	0.081
2.40	2.20	13.3	0.0	0.012	0.000	11.10	0.40	444.40	42.35	27.75	0.00	0.030
2.40	2.20	0.0	48.9	0.043	0.000	34.00	3.00	447.40	42.63	11.33	0.00	0.061
2.50	2.40	12.1	0.0	0.011	0.000	10.05	0.45	447.85	42.68	22.33	0.00	0.037
2.40	2.30	0.0	49.2	0.043	0.000	41.80	2.00	449.85	42.87	20.90	0.00	0.041
2.50	2.40	12.1	0.0	0.011	0.000	20.00	0.20	450.05	42.89	*****	0.00	0.017
2.50	2.40	0.0	49.1	0.043	0.000	32.50	2.00	452.05	43.08	16.25	0.00	0.041
2.60	2.60	12.1	0.0	0.011	0.000	11.90	0.60	452.65	43.13	19.83	0.00	0.050
2.30	2.20	0.0	49.1	0.043	0.000	40.50	3.00	455.65	43.42	13.50	0.00	0.061

TABLE A34 (CONTINUED)

RESULTS OF RUN LC34
[2.02 HCPV WF=>0.20 RHCPV CO2 @ 2.5MPa (0.24g-mol) 4:1 WAG,10 Slugs]

Porosity [%] = 36.5
Oil Viscosity [mPa.s] = 882.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.46

Pore Volume [cm3] = 1134.0
Initial Oil Saturation [%] = 92.5
Hydrocarbon Pore Volume [cm3] = 1049.4
Carbon Dioxide Retention [%inj] = 36.91

Connate Water Saturation [%] = 7.5
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 9.9100
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.50	2.40	12.1	0.0	0.011	0.000	14.30	0.20	455.85	43.44	71.50	0.00	0.017
2.40	2.30	0.0	49.1	0.043	0.000	33.50	1.50	457.35	43.58	22.33	0.00	0.031
2.50	2.40	12.1	0.0	0.011	0.000	20.90	0.60	457.95	43.64	34.83	0.00	0.050
2.50	2.40	0.0	49.1	0.043	0.000	33.50	2.70	460.65	43.90	12.41	0.00	0.055
2.60	2.50	12.1	0.0	0.011	0.000	9.50	0.75	461.40	43.97	12.67	0.00	0.062
2.50	2.40	0.0	49.2	0.043	0.000	40.00	2.00	463.40	44.16	20.00	0.00	0.041
2.50	2.40	12.1	0.0	0.011	0.000	14.50	0.50	463.90	44.21	29.00	0.00	0.041
2.50	2.45	0.0	49.1	0.043	0.000	31.50	1.50	465.40	44.35	21.00	0.00	0.031
0.10	0.10	0.0	0.0	0.000	2.230	148.00	182.00	647.40	61.69	0.81	12.25	

TABLE A35

RESULTS OF RUN LC35
[2.02 HCPV WF=>0.20 RHCPV CO2 @ 2.5MPa (0.24g-mol) 4:1 WAG,10 Slugs]

Porosity [%] = 36.5
Oil Viscosity [mPa.s] = 882.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 16.64

Pore Volume [cm3] = 1134.0
Initial Oil Saturation [%] = 54.2
Hydrocarbon Pore Volume [cm3] = 614.4
Carbon Dioxide Retention [%inj] = 36.91

Connate Water Saturation [%] = 45.8
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 9.9100
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.50	2.40	12.1	0.0	0.011	0.000	13.70	0.50	0.50	0.08	27.40	0.00	0.041
2.50	2.40	0.0	49.1	0.043	0.000	43.00	3.50	4.00	0.65	12.29	0.00	0.071
2.40	2.30	12.1	0.0	0.011	0.000	12.75	1.00	5.00	0.81	12.75	0.00	0.083
2.50	2.40	0.0	49.2	0.043	0.000	32.00	4.00	9.00	1.46	8.00	0.00	0.081
2.40	2.20	13.3	0.0	0.012	0.000	11.10	0.40	9.40	1.53	27.75	0.00	0.030
2.40	2.20	0.0	48.9	0.043	0.000	34.00	3.00	12.40	2.02	11.33	0.00	0.061
2.50	2.40	12.1	0.0	0.011	0.000	10.05	0.45	12.85	2.09	22.33	0.00	0.037
2.40	2.30	0.0	49.2	0.043	0.000	41.80	2.00	14.85	2.42	20.90	0.00	0.041
2.50	2.40	12.1	0.0	0.011	0.000	20.00	0.20	15.05	2.45	*****	0.00	0.017
2.50	2.40	0.0	49.1	0.043	0.000	32.50	2.00	17.05	2.78	16.25	0.00	0.041
2.60	2.60	12.1	0.0	0.011	0.000	11.90	0.60	17.65	2.87	19.83	0.00	0.050
2.30	2.20	0.0	49.1	0.043	0.000	40.50	3.00	20.65	3.36	13.50	0.00	0.061
2.50	2.40	12.1	0.0	0.011	0.000	14.30	0.20	20.85	3.39	71.50	0.00	0.017
2.40	2.30	0.0	49.1	0.043	0.000	33.50	1.50	22.35	3.64	22.33	0.00	0.031
2.50	2.40	12.1	0.0	0.011	0.000	20.90	0.60	22.95	3.74	34.83	0.00	0.050
2.50	2.40	0.0	49.1	0.043	0.000	33.50	2.70	25.65	4.17	12.41	0.00	0.055
2.60	2.50	12.1	0.0	0.011	0.000	9.50	0.75	26.40	4.30	12.67	0.00	0.062

TABLE A35 (CONTINUED)

RESULTS OF RUN LC35
[2.02 HCPV WF=>0.20 RHCPV CO2 @ 2.5MPa (0.24g-mol) 4:1 WAG,10 Slugs]

Porosity [%] = 36.5
Oil Viscosity [mPa.s] = 882.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 16.64

Pore Volume [cm3] = 1134.0
Initial Oil Saturation [%] = 54.2
Hydrocarbon Pore Volume [cm3] = 614.4
Carbon Dioxide Retention [%inj] = 36.91

Connate Water Saturation [%] = 45.8
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 9.9100
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.50	2.40	0.0	49.2	0.043	0.000	40.00	2.00	28.40	4.62	20.00	0.00	0.041
2.50	2.40	12.1	0.0	0.011	0.000	14.50	0.50	28.90	4.70	29.00	0.00	0.041
2.50	2.45	0.0	49.1	0.043	0.000	31.50	1.50	30.40	4.95	21.00	0.00	0.031
0.10	0.10	0.0	0.0	0.000	2.230	148.00	182.00	212.40	34.57	0.81	12.25	

TABLE A36

RESULTS OF RUN LC36

[0.05 HCPV CO2 @ 2.5MPa (0.064g-mol) 4:1 WAG,10 Slugs]

Porosity [%] = 37.1
Oil Viscosity [mPa.s] = 1130.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 3.31

Pore Volume [cm3] = 1155.0
Initial Oil Saturation [%] = 91.8
Hydrocarbon Pore Volume [cm3] = 1060.7
Carbon Dioxide Retention [%inj] = 99.39

Connate Water Saturation [%] = 8.2
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 11.1700
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.70	2.50	6.1	0.0	0.005	0.000	0.00	3.00	3.00	0.28	0.00	0.00	0.496
2.60	2.50	0.0	21.2	0.018	0.000	0.00	16.75	19.75	1.86	0.00	0.00	0.791
2.60	2.50	4.8	0.0	0.004	0.000	0.00	4.50	24.25	2.29	0.00	0.00	0.930
2.60	2.30	0.0	21.2	0.018	0.000	0.00	19.25	43.50	4.10	0.00	0.00	0.908
2.70	2.40	6.1	0.0	0.005	0.000	0.00	6.00	49.50	4.67	0.00	0.00	0.992
2.50	2.30	0.0	21.2	0.018	0.000	0.00	22.50	72.00	6.79	0.00	0.00	1.061
2.50	2.40	4.8	0.0	0.004	0.000	0.00	6.25	78.25	7.38	0.00	0.00	1.291
2.60	2.40	0.0	21.2	0.018	0.000	0.00	20.00	98.25	9.26	0.00	0.00	0.942
2.50	2.40	7.3	0.0	0.006	0.000	0.00	6.90	105.15	9.91	0.00	0.00	0.949
2.48	2.40	0.0	21.2	0.018	0.000	0.25	19.25	124.40	11.73	0.01	0.00	0.906
2.50	2.40	4.8	0.0	0.004	0.000	0.20	4.80	129.20	12.18	0.04	0.00	0.992
2.54	2.38	0.0	21.2	0.018	0.000	3.00	20.50	149.70	14.11	0.15	0.00	0.966
2.60	2.50	4.8	0.0	0.004	0.000	0.75	4.95	154.65	14.58	0.15	0.00	1.023
2.50	2.40	0.0	21.2	0.018	0.000	4.00	17.00	171.65	16.18	0.24	0.00	0.801
2.58	2.40	4.8	0.0	0.004	0.000	0.90	5.00	176.65	16.65	0.18	0.00	1.033
2.50	2.40	0.0	21.2	0.018	0.000	8.00	14.00	190.65	17.97	0.57	0.00	0.660
2.50	2.40	6.1	0.0	0.005	0.000	1.20	5.40	196.05	18.48	0.22	0.00	0.893

TABLE A36 (CONTINUED)

RESULTS OF RUN LC36
[0.05 HCPV CO2 @ 2.5MPa (0.064g-mol) 4:1 WAG,10 Slugs]

Porosity [%] = 37.1
Oil Viscosity [mPa.s] = 1130.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 3.31

Pore Volume [cm3] = 1155.0
Initial Oil Saturation [%] = 91.8
Hydrocarbon Pore Volume [cm3] = 1060.7
Carbon Dioxide Retention [%inj] = 99.39

Connate Water Saturation [%] = 8.2
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 11.1700
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
2.45	2.38	0.0	22.7	0.020	0.000	8.00	13.50	209.55	19.76	0.59	0.00	0.594
2.56	2.42	4.8	0.0	0.004	0.000	2.00	4.90	214.45	20.22	0.41	0.00	1.012
2.50	2.40	0.0	21.3	0.018	0.000	7.20	9.70	224.15	21.13	0.74	0.00	0.456
2.50	2.44	0.0	252.3	0.218	0.010	151.50	90.35	314.50	29.65	1.68	0.11	0.358
2.54	2.24	0.0	253.8	0.220	0.000	204.00	52.00	366.50	34.55	3.92	0.00	0.205
2.48	2.40	0.0	186.9	0.162	0.000	166.00	20.75	387.25	36.51	8.00	0.00	0.111
2.50	2.42	0.0	236.5	0.205	0.000	222.00	20.50	407.75	38.44	10.83	0.00	0.087
2.50	2.40	0.0	211.2	0.183	0.000	200.00	14.50	422.25	39.81	13.79	0.00	0.069
2.52	2.40	0.0	246.4	0.213	0.000	234.50	14.00	436.25	41.13	16.75	0.00	0.057
2.50	2.40	0.0	184.9	0.160	0.000	178.00	8.50	444.75	41.93	20.94	0.00	0.046
2.50	2.40	0.0	240.0	0.208	0.000	237.00	10.50	455.25	42.92	22.57	0.00	0.044
2.54	2.40	0.0	213.6	0.185	0.000	204.00	9.80	465.05	43.84	20.82	0.00	0.046
0.10	0.10	0.0	0.0	0.000	0.000	29.50	27.50	492.55	46.44	1.07	0.00	

TABLE A37

RESULTS OF RUN LC37
[0.2 HCPV CO2 @ 1.0 MPa (0.076 g-mol) 4:1 WAG,10 Slugs, LIVE OIL]

Porosity [%] = 36.7
Oil Viscosity [mPa.s] = 1046.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 3.40

Pore Volume [cm3] = 1142.0
Initial Oil Saturation [%] = 88.7
Hydrocarbon Pore Volume [cm3] = 880.0
Carbon Dioxide Retention [%inj] = *****

Connate Water Saturation [%] = 11.3
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 9.1800
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	0.90	18.0	0.0	0.016	0.040	0.00	14.80	14.80	1.68	0.00	2.70	0.823
1.00	0.90	0.0	70.4	0.062	0.200	0.00	65.50	80.30	9.12	0.00	3.05	0.930
1.00	0.96	17.5	0.0	0.015	0.090	0.00	28.50	108.80	12.36	0.00	3.16	1.625
1.00	0.80	0.0	70.4	0.062	0.180	2.00	59.90	168.70	19.17	0.03	3.01	0.851
1.10	0.90	24.0	0.0	0.021	0.030	4.50	11.60	180.30	20.49	0.39	2.59	0.483
1.00	0.90	0.0	70.0	0.061	0.170	1.00	54.90	235.20	26.73	0.02	3.10	0.784
1.00	0.90	18.2	0.0	0.016	0.030	5.50	8.40	243.60	27.68	0.65	3.57	0.462
1.00	0.90	0.0	71.4	0.062	0.160	20.50	40.40	284.00	32.27	0.51	3.96	0.566
1.00	0.90	17.5	0.0	0.015	0.040	10.00	8.00	292.00	33.16	1.25	5.00	0.456
1.00	0.90	0.0	70.3	0.062	0.090	37.00	17.00	309.00	35.11	2.18	5.29	0.242
1.00	0.95	18.3	0.0	0.016	0.030	12.20	4.80	313.80	35.66	2.54	6.25	0.263
1.00	0.90	0.0	70.4	0.062	0.100	45.00	13.00	326.80	37.14	3.46	7.69	0.185
1.20	0.95	18.1	0.0	0.016	0.020	13.00	2.90	329.70	37.47	4.48	6.90	0.160
1.00	0.85	0.0	70.4	0.062	0.110	55.50	13.00	342.70	38.94	4.27	8.46	0.185
1.00	0.90	17.7	0.0	0.015	0.020	14.90	2.10	344.80	39.18	7.10	9.52	0.119
1.00	0.90	0.0	71.6	0.063	0.090	46.00	13.00	357.80	40.66	3.54	6.92	0.182
1.00	0.90	17.5	0.0	0.015	0.010	11.50	3.40	361.20	41.05	3.38	2.94	0.194

TABLE A37 (CONTINUED)

RESULTS OF RUN LC37
[0.2 HCPV CO2 @ 1.0 MPa (0.076 g-mol) 4:1 WAG,10 Slugs, LIVE OIL]

Porosity [%] = 36.7
Oil Viscosity [mPa.s] = 1046.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 3.40

Pore Volume [cm3] = 1142.0
Initial Oil Saturation [%] = 88.7
Hydrocarbon Pore Volume [cm3] = 880.0
Carbon Dioxide Retention [%inj] = *****

Connate Water Saturation [%] = 11.3
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 9.1800
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	0.90	0.0	69.6	0.061	0.430	92.50	8.50	369.70	42.01	10.88	50.59	0.122
1.00	0.90	17.5	0.0	0.015	0.000	0.01	0.01	369.71	42.01	1.00	0.00	0.001
1.00	0.90	0.0	70.5	0.062	0.310	2.00	12.20	381.91	43.40	0.16	25.41	0.173
1.00	0.90	0.0	232.4	0.204	0.260	184.20	18.00	399.91	45.44	10.23	14.44	0.077
1.00	0.85	0.0	221.4	0.194	0.310	221.00	40.00	439.91	49.99	5.52	7.75	0.181
1.00	0.90	0.0	239.1	0.209	0.350	204.00	16.00	455.91	51.81	12.75	21.88	0.067
1.00	0.95	0.0	229.9	0.201	0.250	202.20	8.30	464.21	52.75	24.36	30.12	0.036
1.00	0.95	0.0	235.1	0.206	0.300	229.50	8.50	472.71	53.72	27.00	35.29	0.036
1.00	0.96	0.0	288.5	0.253	0.270	280.50	9.50	482.21	54.80	29.53	28.42	0.033
1.20	0.10	0.0	245.5	0.215	0.160	242.00	5.50	487.71	55.42	44.00	29.09	0.022
1.00	0.90	0.0	237.5	0.208	0.110	233.50	5.00	492.71	55.99	46.70	22.00	0.021
1.00	0.90	0.0	223.4	0.196	0.070	220.00	5.50	498.21	56.61	40.00	12.73	0.025
1.00	0.90	0.0	347.9	0.305	0.070	342.50	10.50	508.71	57.81	32.62	6.67	0.030
0.10	0.10	0.0	0.0	0.000	0.350	103.50	76.00	584.71	66.44	1.36	4.61	

TABLE A38

RESULTS OF RUN LC38
[0.4 HCPV CO2 @ 1.0 MPa (0.198 g-mol) 4:1 WAG,10 Slugs, LIVE OIL]

Porosity [%] = 39.9
Oil Viscosity [mPa.s] = 1046.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 6.58
Pore Volume [cm3] = 1239.0
Initial Oil Saturation [%] = 90.5
Hydrocarbon Pore Volume [cm3] = 1140.0
Carbon Dioxide Retention [%inj] = *****
Connate Water Saturation [%] = 9.5
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 11.8000
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	1.00	45.3	0.0	0.037	0.080	0.50	29.60	29.60	2.60	0.02	2.70	0.653
1.00	0.90	0.0	176.5	0.142	0.460	1.00	177.00	206.60	18.12	0.01	2.60	1.003
1.00	0.90	46.5	0.0	0.038	0.170	0.40	19.60	226.20	19.84	0.02	8.67	0.422
1.00	0.95	0.0	183.6	0.148	0.280	63.50	98.70	324.90	28.50	0.64	2.84	0.538
1.00	0.95	45.6	0.0	0.037	0.070	35.00	14.50	339.40	29.77	2.41	4.83	0.318
1.00	0.98	0.0	182.9	0.148	0.300	117.00	32.70	372.10	32.64	3.58	9.17	0.179
1.00	0.99	45.9	0.0	0.037	0.050	33.10	6.90	379.00	33.25	4.80	7.25	0.150
1.00	0.99	0.0	184.1	0.149	0.420	109.00	59.20	438.20	38.44	1.84	7.09	0.322
1.00	0.99	46.5	0.0	0.038	0.080	26.20	11.00	449.20	39.40	2.38	7.27	0.236
1.00	0.95	0.0	184.0	0.149	0.450	113.50	29.50	478.70	41.99	3.85	15.25	0.160
1.10	0.99	45.6	0.0	0.037	0.080	36.00	7.70	486.40	42.67	4.68	10.39	0.169
1.00	0.95	0.0	182.4	0.147	0.430	102.00	31.50	517.90	45.43	3.24	13.65	0.173
1.00	0.95	45.6	0.0	0.037	0.080	37.00	5.60	523.50	45.92	6.61	14.29	0.123
1.00	0.96	0.0	184.6	0.149	0.420	115.00	19.00	542.50	47.59	6.05	22.11	0.103
1.10	0.90	45.6	0.0	0.037	0.060	33.70	3.30	545.80	47.88	10.21	18.18	0.072
1.00	0.98	0.0	184.6	0.149	0.350	144.50	14.50	560.30	49.15	9.97	24.14	0.079
1.00	0.99	45.6	0.0	0.037	0.070	59.50	3.50	563.80	49.46	17.00	20.00	0.077

TABLE A38 (CONTINUED)

RESULTS OF RUN LC38

[0.4 HCPV CO2 @ 1.0 MPa (0.198 g-mol) 4:1 WAG,10 Slugs, LIVE OIL]

Porosity [%] = 39.9
Oil Viscosity [mPa.s] = 1046.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 6.58

Pore Volume [cm3] = 1239.0
Initial Oil Saturation [%] = 90.5
Hydrocarbon Pore Volume [cm3] = 1140.0
Carbon Dioxide Retention [%inj] = *****

Connate Water Saturation [%] = 9.5
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 11.8000
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	0.97	0.0	183.3	0.148	0.060	133.50	11.50	575.30	50.46	11.61	5.22	0.063
1.00	0.98	45.6	0.0	0.037	0.060	37.20	4.00	579.30	50.82	9.30	15.00	0.088
1.00	0.99	0.0	182.5	0.147	0.530	127.00	11.00	590.30	51.78	11.55	48.18	0.060
1.00	0.90	0.0	238.7	0.193	0.380	227.00	20.50	610.80	53.58	11.07	18.54	0.086
1.00	0.95	0.0	248.5	0.201	0.320	222.20	11.80	622.60	54.61	18.83	27.12	0.047
1.00	0.99	0.0	273.8	0.221	0.350	236.00	7.50	630.10	55.27	31.47	46.67	0.027
1.00	0.90	0.0	222.3	0.179	0.230	222.50	9.50	639.60	56.11	23.42	24.21	0.043
1.00	0.98	0.0	262.7	0.212	0.220	254.50	5.50	645.10	56.59	46.27	40.00	0.021
0.10	0.10	0.0	0.0	0.000	1.930	155.00	94.00	739.10	64.83	1.65	20.53	

TABLE A39

RESULTS OF RUN LC39
[0.1 HCPV CO2 @ 1.0 MPa (0.047 g-mol) 4:1 WAG,10 Slugs, LIVE OIL]

Porosity [%] = 36.7
Oil Viscosity [mPa.s] = 1046.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 1.97

Pore Volume [cm3] = 1142.0
Initial Oil Saturation [%] = 95.0
Hydrocarbon Pore Volume [cm3] = 1085.0
Carbon Dioxide Retention [%inj] = *****

Connate Water Saturation [%] = 5.0
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 13.6000
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.20	1.01	10.8	0.0	0.009	0.010	0.20	6.80	6.80	0.63	0.03	1.47	0.631
1.30	1.01	0.0	43.5	0.038	0.110	0.10	45.90	52.70	4.86	0.00	2.40	1.056
1.20	1.01	10.8	0.0	0.009	0.020	0.05	11.15	63.85	5.88	0.00	1.79	1.035
1.20	1.01	0.0	44.2	0.039	0.120	0.05	42.15	106.00	9.77	0.00	2.85	0.954
1.20	1.01	10.8	0.0	0.009	0.010	0.05	15.95	121.95	11.24	0.00	0.63	1.481
1.10	1.01	0.0	43.8	0.038	0.120	0.20	39.30	161.25	14.86	0.01	3.05	0.898
1.20	1.10	11.3	0.0	0.010	0.030	0.05	11.65	172.90	15.94	0.00	2.58	1.036
1.20	1.01	0.0	44.1	0.039	0.110	0.80	34.70	207.60	19.13	0.02	3.17	0.787
1.10	1.00	10.8	0.0	0.009	0.080	6.00	21.50	229.10	21.12	0.28	3.72	1.996
1.20	1.01	0.0	44.9	0.039	0.070	9.00	18.40	247.50	22.81	0.49	3.80	0.410
1.20	1.01	10.8	0.0	0.009	0.010	0.40	4.50	252.00	23.23	0.09	2.22	0.418
1.10	1.00	0.0	43.4	0.038	0.090	14.00	19.20	271.20	25.00	0.73	4.69	0.442
1.10	1.00	10.8	0.0	0.009	0.050	13.30	7.80	279.00	25.71	1.71	6.41	0.724
1.10	1.00	0.0	44.5	0.039	0.040	13.90	9.30	288.30	26.57	1.49	4.30	0.209
1.20	1.10	10.8	0.0	0.009	0.050	16.75	11.75	300.05	27.65	1.43	4.26	1.091
1.10	1.00	0.0	45.0	0.039	0.100	24.00	19.00	319.05	29.41	1.26	5.26	0.422
1.10	1.01	11.4	0.0	0.010	0.040	13.40	4.50	323.55	29.82	2.98	8.89	0.395

TABLE A39 (CONTINUED)

RESULTS OF RUN LC39
[0.1 HCPV CO2 @ 1.0 MPa (0.047 g-mol) 4:1 WAG,10 Slugs, LIVE OIL]

Porosity [%] = 36.7
Oil Viscosity [mPa.s] = 1046.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 1.97

Pore Volume [cm3] = 1142.0
Initial Oil Saturation [%] = 95.0
Hydrocarbon Pore Volume [cm3] = 1085.0
Carbon Dioxide Retention [%inj] = *****

Connate Water Saturation [%] = 5.0
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 13.6000
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	45.3	0.040	0.120	18.00	12.50	336.05	30.97	1.44	9.60	0.276
1.20	1.10	10.8	0.0	0.009	0.030	11.90	3.10	339.15	31.26	3.84	9.68	0.288
1.10	1.00	0.0	44.0	0.039	0.140	25.50	18.50	357.65	32.96	1.38	7.57	0.420
1.20	1.00	0.0	225.7	0.198	0.250	120.00	99.50	457.15	42.13	1.21	2.51	0.441
1.10	1.01	0.0	221.6	0.194	0.260	162.50	64.50	521.65	48.08	2.52	4.03	0.291
1.15	1.05	0.0	247.6	0.217	0.340	192.00	43.50	565.15	52.09	4.41	7.82	0.176
1.10	1.05	0.0	245.1	0.215	0.360	218.50	22.00	587.15	54.12	9.93	16.36	0.090
1.20	1.02	0.0	253.9	0.222	0.300	233.00	19.50	606.65	55.91	11.95	15.38	0.077
1.10	1.01	0.0	242.5	0.212	0.260	219.50	10.50	617.15	56.88	20.90	24.76	0.043
1.10	1.06	0.0	221.9	0.194	0.210	235.50	6.50	623.65	57.48	36.23	32.31	0.029
1.10	1.05	0.0	258.6	0.226	0.130	242.20	10.30	633.95	58.43	23.51	12.62	0.040
1.10	1.02	0.0	461.9	0.404	0.180	450.50	13.30	647.25	59.65	33.87	13.53	0.029
0.01	0.01	0.0	0.0	0.000	1.200	145.00	31.00	678.25	62.51	4.68	38.71	

TABLE A40

RESULTS OF RUN LC40

[0.2 HCPV CO2 @ 1.0 MPa (0.091 g-mol) 4:1 WAG,10 Slugs, LIVE OIL]

Porosity [%] = 35.7
Oil Viscosity [mPa.s] = 1046.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.04

Pore Volume [cm3] = 1110.0
Initial Oil Saturation [%] = 94.1
Hydrocarbon Pore Volume [cm3] = 1044.0
Carbon Dioxide Retention [%inj] = *****

Connate Water Saturation [%] = 5.9
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 10.2000
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.20	1.00	21.1	0.0	0.019	0.030	0.01	16.69	16.69	1.60	0.00	1.80	0.793
1.10	1.00	0.0	83.6	0.075	0.200	0.00	84.10	100.79	9.65	0.00	2.38	1.007
1.20	1.00	20.9	0.0	0.019	0.050	0.00	16.30	117.09	11.22	0.00	3.07	0.781
1.10	1.00	0.0	83.7	0.075	0.250	0.00	75.00	192.09	18.40	0.00	3.33	0.896
1.20	1.00	21.6	0.0	0.019	0.060	0.62	19.88	211.97	20.30	0.03	3.02	0.919
1.20	1.00	0.0	83.5	0.075	0.240	19.20	56.80	268.77	25.74	0.34	4.23	0.680
1.10	1.00	23.1	0.0	0.021	0.040	11.10	9.90	278.67	26.69	1.12	4.04	0.429
1.20	1.00	0.0	84.8	0.076	0.200	38.50	29.50	308.17	29.52	1.31	6.78	0.348
1.20	1.00	21.1	0.0	0.019	0.030	13.10	8.40	316.57	30.32	1.56	3.57	0.397
1.20	1.00	0.0	84.4	0.076	0.150	44.50	21.10	337.67	32.34	2.11	7.11	0.250
1.10	1.00	31.7	0.0	0.029	0.060	32.80	9.70	347.37	33.27	3.38	6.19	0.306
1.10	1.00	0.0	83.6	0.075	0.240	45.00	9.30	356.67	34.16	4.84	25.81	0.111
1.10	1.00	21.1	0.0	0.019	0.040	20.20	4.40	361.07	34.59	4.59	9.09	0.209
1.20	1.00	0.0	83.6	0.075	0.240	44.40	10.90	371.97	35.63	4.07	22.02	0.130
1.05	1.00	20.9	0.0	0.019	0.050	22.00	3.40	375.37	35.95	6.47	14.71	0.163
1.10	1.00	0.0	83.5	0.075	0.280	49.40	14.50	389.87	37.34	3.41	19.31	0.174
1.10	1.00	20.9	0.0	0.019	0.040	19.30	4.10	393.97	37.74	4.71	9.76	0.197

TABLE A40 (CONTINUED)

RESULTS OF RUN LC40
[0.2 HCPV CO2 @ 1.0 MPa (0.091 g-mol) 4:1 WAG,10 Slugs, LIVE OIL]

Porosity [%] = 35.7
Oil Viscosity [mPa.s] = 1046.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.04

Pore Volume [cm3] = 1110.0
Initial Oil Saturation [%] = 94.1
Hydrocarbon Pore Volume [cm3] = 1044.0
Carbon Dioxide Retention [%inj] = *****

Connate Water Saturation [%] = 5.9
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 10.2000
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.20	1.00	0.0	85.4	0.077	0.150	54.90	10.90	404.87	38.78	5.04	13.76	0.128
1.20	1.00	20.9	0.0	0.019	0.030	15.00	2.93	407.80	39.06	5.12	10.24	0.140
1.10	1.00	0.0	83.6	0.075	0.160	60.80	9.50	417.30	39.97	6.40	16.84	0.114
1.10	1.00	0.0	95.9	0.086	0.160	88.50	8.00	425.30	40.74	11.06	20.00	0.083
1.10	1.00	0.0	92.6	0.083	0.130	85.00	10.60	435.90	41.75	8.02	12.26	0.114
1.10	1.00	0.0	227.9	0.205	0.270	182.50	40.20	476.10	45.60	4.54	6.72	0.176
1.10	1.00	0.0	248.5	0.224	0.350	213.50	34.50	510.60	48.91	6.19	10.14	0.139
1.10	1.00	0.0	246.8	0.222	0.320	230.60	18.90	529.50	50.72	12.20	16.93	0.077
1.10	1.00	0.0	245.1	0.221	0.280	223.50	23.00	552.50	52.92	9.72	12.17	0.094
1.20	1.00	0.0	247.7	0.223	0.230	236.00	12.10	564.60	54.08	19.50	19.01	0.049
1.20	1.00	0.0	490.1	0.441	0.250	480.60	14.50	579.10	55.47	33.14	17.24	0.030
1.10	1.00	0.0	492.3	0.444	0.150	485.00	11.50	590.60	56.57	42.17	13.04	0.023
1.10	1.00	0.0	40.8	0.037	0.570	40.00	3.65	594.25	56.92	10.96	156.16	0.089
0.10	0.10	0.0	0.0	0.000	0.790	156.00	69.00	663.25	63.53	2.26	11.45	

TABLE A41

RESULTS OF RUN LC41
[0.2 HCPV CO2 @ 1.0 MPa (0.091 g-mol) 4:1 WAG,10 Slugs, LIVE OIL]

Porosity [%] = 38.9
Oil Viscosity [mPa.s] = 1046.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 3.75

Pore Volume [cm3] = 1210.0
Initial Oil Saturation [%] = 92.3
Hydrocarbon Pore Volume [cm3] = 1117.0
Carbon Dioxide Retention [%inj] = *****

Connate Water Saturation [%] = 7.7
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 14.1500
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.20	1.00	22.3	0.0	0.018	0.020	0.01	15.69	15.69	1.40	0.00	1.27	0.704
1.20	1.00	0.0	89.4	0.074	0.230	0.00	96.00	111.69	10.00	0.00	2.40	1.074
1.20	1.00	22.3	0.0	0.018	0.060	0.00	23.70	135.39	12.12	0.00	2.53	1.063
1.20	1.00	0.0	89.4	0.074	0.220	9.80	82.55	217.94	19.51	0.12	2.67	0.923
1.10	1.00	22.3	0.0	0.018	0.050	10.00	15.60	233.54	20.91	0.64	3.21	0.700
1.10	1.00	0.0	89.1	0.074	0.290	23.90	45.40	278.94	24.97	0.53	6.39	0.509
1.20	1.00	22.3	0.0	0.018	0.040	8.50	11.30	290.24	25.98	0.75	3.54	0.507
1.20	1.00	0.0	90.5	0.075	0.210	46.30	31.20	321.44	28.78	1.48	6.73	0.345
1.10	1.00	22.3	0.0	0.018	0.080	17.00	5.40	326.84	29.26	3.15	14.81	0.242
1.20	1.00	0.0	89.5	0.074	0.370	46.00	22.00	348.84	31.23	2.09	16.82	0.246
1.10	1.00	22.3	0.0	0.018	0.050	19.00	7.85	356.69	31.93	2.42	6.37	0.352
1.20	1.00	0.0	89.5	0.074	0.100	67.00	12.80	369.49	33.08	5.23	7.81	0.143
1.20	1.10	22.3	0.0	0.018	0.020	19.30	6.10	375.59	33.62	3.16	3.28	0.274
1.10	1.00	0.0	89.4	0.074	0.420	45.00	18.00	393.59	35.24	2.50	23.33	0.201
1.20	1.00	22.3	0.0	0.018	0.060	21.60	5.30	398.89	35.71	4.08	11.32	0.238
1.10	1.00	0.0	89.4	0.074	0.080	72.00	11.50	410.39	36.74	6.26	6.96	0.129
1.20	1.00	22.3	0.0	0.018	0.020	15.50	2.70	413.09	36.98	5.74	7.41	0.121

TABLE A41 (CONTINUED)

RESULTS OF RUN LC41
[0.2 HCPV CO2 @ 1.0 MPa (0.091 g-mol) 4:1 WAG,10 Slugs, LIVE OIL]

Porosity [%] = 38.9
Oil Viscosity [mPa.s] = 1046.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 3.75

Pore Volume [cm3] = 1210.0
Initial Oil Saturation [%] = 92.3
Hydrocarbon Pore Volume [cm3] = 1117.0
Carbon Dioxide Retention [%inj] = *****

Connate Water Saturation [%] = 7.7
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 14.1500
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	90.9	0.075	0.090	74.00	16.40	429.49	38.45	4.51	5.49	0.180
1.10	1.00	22.5	0.0	0.019	0.020	15.50	2.70	432.19	38.69	5.74	7.41	0.120
1.20	1.00	0.0	89.4	0.074	0.200	62.50	11.20	443.39	39.69	5.58	17.86	0.125
1.20	1.00	0.0	280.4	0.232	1.110	205.40	49.60	492.99	44.14	4.14	22.38	0.177
1.20	1.00	0.0	240.1	0.198	0.340	186.00	61.00	553.99	49.60	3.05	5.57	0.254
1.10	1.00	0.0	247.6	0.205	0.260	223.30	25.70	579.69	51.90	8.69	10.12	0.104
1.10	1.00	0.0	246.8	0.204	0.250	226.40	21.60	601.29	53.83	10.48	11.57	0.088
1.10	1.00	0.0	249.9	0.207	0.200	228.50	23.50	624.79	55.93	9.72	8.51	0.094
1.20	1.00	0.0	249.7	0.206	0.180	240.50	11.50	636.29	56.96	20.91	15.65	0.046
1.20	1.00	0.0	250.0	0.207	0.140	236.50	16.50	652.79	58.44	14.33	8.48	0.066
0.10	0.10	0.0	0.0	0.000	1.320	164.00	73.00	725.79	64.98	2.25	18.08	

TABLE A42

RESULTS OF RUN LC42
[0.2 HCPV CO2 @ 1.0 MPa (0.089 g-mol) 4:1 WAG,10 Slugs]

Porosity [%] = 36.1
Oil Viscosity [mPa.s] = 1046.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.72
Pore Volume [cm3] = 1135.0
Initial Oil Saturation [%] = 90.2
Hydrocarbon Pore Volume [cm3] = 1024.0
Carbon Dioxide Retention [%inj] = 9.69
Connate Water Saturation [%] = 9.8
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 10.9900
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	1.00	20.5	0.0	0.018	0.000	0.00	4.50	4.50	0.44	0.00	0.00	0.220
1.00	1.00	82.0	0.0	0.072	0.000	0.50	76.50	81.00	7.91	0.01	0.00	0.933
1.00	1.00	20.5	0.0	0.018	0.000	0.20	12.20	93.20	9.10	0.02	0.00	0.596
1.00	0.90	0.0	82.0	0.072	0.000	14.00	58.50	151.70	14.81	0.24	0.00	0.714
1.00	0.95	20.5	0.0	0.018	0.000	8.90	14.60	166.30	16.24	0.61	0.00	0.713
1.00	0.90	0.0	82.0	0.072	0.010	29.90	36.10	202.40	19.77	0.83	0.28	0.440
1.00	0.95	20.5	0.0	0.018	0.010	16.50	8.70	211.10	20.62	1.90	1.15	0.425
1.00	0.98	0.0	83.9	0.074	0.100	42.20	20.80	231.90	22.65	2.03	4.81	0.248
1.00	0.99	21.1	0.0	0.019	0.020	18.50	6.50	238.40	23.28	2.85	3.08	0.307
1.00	0.90	0.0	82.0	0.072	0.150	42.20	18.30	256.70	25.07	2.31	8.20	0.223
1.00	0.90	20.5	0.0	0.018	0.030	17.60	4.60	261.30	25.52	3.83	6.52	0.225
1.05	1.00	0.0	82.0	0.072	0.140	48.00	17.80	279.10	27.26	2.70	7.87	0.217
1.00	0.95	20.5	0.0	0.018	0.040	18.00	4.00	283.10	27.65	4.50	10.00	0.195
1.00	0.99	0.0	83.2	0.073	0.160	51.90	16.80	299.90	29.29	3.09	9.52	0.202
1.00	0.90	20.5	0.0	0.018	0.050	17.20	4.20	304.10	29.70	4.10	11.90	0.205
1.01	0.99	0.0	81.5	0.072	0.170	47.20	12.40	316.50	30.91	3.81	13.71	0.152
1.00	0.99	20.5	0.0	0.018	0.050	15.10	3.60	320.10	31.26	4.19	13.89	0.176

TABLE A42 (CONTINUED)

RESULTS OF RUN LC42
[0.2 HCPV CO2 @ 1.0 MPa (0.089 g-mol) 4:1 WAG,10 Slugs]

Porosity [%] = 36.1
Oil Viscosity [mPa.s] = 1046.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.72

Pore Volume [cm3] = 1135.0
Initial Oil Saturation [%] = 90.2
Hydrocarbon Pore Volume [cm3] = 1024.0
Carbon Dioxide Retention [%inj] = 9.69

Connate Water Saturation [%] = 9.8
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 10.9900
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	1.00	0.0	82.0	0.072	0.260	56.00	12.10	332.20	32.44	4.63	21.49	0.148
1.00	1.00	20.5	0.0	0.018	0.060	21.10	6.80	339.00	33.11	3.10	8.82	0.332
1.00	1.00	0.0	82.0	0.072	0.180	43.00	19.50	358.50	35.01	2.21	9.23	0.238
1.00	1.00	0.0	268.5	0.237	0.530	191.00	68.00	426.50	41.65	2.81	7.79	0.253
1.00	1.00	0.0	250.7	0.221	0.410	221.50	31.50	458.00	44.73	7.03	13.02	0.126
1.00	1.00	0.0	244.0	0.215	0.140	234.00	14.00	472.00	46.09	16.71	10.00	0.057
1.00	1.00	0.0	243.9	0.215	0.060	220.50	23.00	495.00	48.34	9.59	2.61	0.094
1.00	1.00	0.0	256.8	0.226	0.050	251.00	7.00	502.00	49.02	35.86	7.14	0.027
1.00	1.00	0.0	202.2	0.178	0.040	199.50	3.50	505.50	49.37	57.00	11.43	0.017
0.10	0.10	0.0	0.0	0.000	0.040	24.50	17.50	523.00	51.07	1.40	2.29	

TABLE A43

RESULTS OF RUN LC43

[2.26 WF => 0.2 RHPV CO2 @ 1.0 MPa (0.039 g-mol) 4:1 WAG, 10 Slugs, LIVE OIL]

Porosity [%] = 35.1
Oil Viscosity [mPa.s] = 1046.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 1.38

Pore Volume [cm3] = 1092.0
Initial Oil Saturation [%] = 92.0
Hydrocarbon Pore Volume [cm3] = 1005.0
Carbon Dioxide Retention [%inj] = *****

Connate Water Saturation [%] = 8.0
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 10.4500
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	222.8	0.204	0.580	12.00	214.00	214.00	21.29	0.06	2.71	0.960
1.10	1.00	0.0	241.8	0.221	0.270	107.00	133.00	347.00	34.53	0.80	2.03	0.550
1.00	1.00	0.0	245.9	0.225	0.140	176.00	72.00	419.00	41.69	2.44	1.94	0.293
1.00	1.00	0.0	240.0	0.220	0.090	194.00	46.00	465.00	46.27	4.22	1.96	0.192
1.00	1.00	0.0	248.1	0.227	0.090	220.00	28.00	493.00	49.05	7.86	3.21	0.113
1.00	1.00	0.0	241.9	0.221	0.090	222.00	21.50	514.50	51.19	10.33	4.19	0.089
1.00	1.00	0.0	255.1	0.234	0.090	240.00	16.00	530.50	52.79	15.00	5.62	0.063
1.00	1.00	0.0	226.7	0.208	0.100	218.50	9.50	540.00	53.73	23.00	10.53	0.042
1.00	1.00	0.0	95.4	0.087	0.030	95.00	7.50	547.50	54.48	12.67	4.00	0.079
1.00	1.00	0.0	240.9	0.221	0.080	232.00	7.50	555.00	55.22	30.93	10.67	0.031
1.00	1.00	0.0	14.8	0.014	0.010	12.00	1.00	556.00	55.32	12.00	10.00	0.068
1.00	1.00	8.9	0.0	0.008	0.010	19.00	1.00	557.00	55.42	19.00	10.00	0.112
1.00	1.00	0.0	36.0	0.033	0.010	28.00	1.60	558.60	55.58	17.50	6.25	0.044
1.00	1.00	8.9	0.0	0.008	0.010	32.00	1.00	559.60	55.68	32.00	10.00	0.112
1.00	1.00	0.0	36.0	0.033	0.010	9.99	0.10	559.70	55.69	99.90	100.00	0.003
1.00	1.00	8.9	0.0	0.008	0.010	32.60	1.20	560.90	55.81	27.17	8.33	0.134
1.00	1.00	0.0	37.0	0.034	0.010	17.00	1.00	561.90	55.91	17.00	10.00	0.027

TABLE A43 (CONTINUED)

RESULTS OF RUN LC43

[2.26 WF => 0.2 RHPV CO2 @ 1.0 MPa (0.039 g-mol) 4:1 WAG, 10 Slugs, LIVE OIL]

Porosity [%] = 35.1
Oil Viscosity [mPa.s] = 1046.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 1.38

Pore Volume [cm3] = 1092.0
Initial Oil Saturation [%] = 92.0
Hydrocarbon Pore Volume [cm3] = 1005.0
Carbon Dioxide Retention [%inj] = *****

Connate Water Saturation [%] = 8.0
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 10.4500
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	1.00	8.9	0.0	0.008	0.010	35.00	1.10	563.00	56.02	31.82	9.09	0.123
1.00	1.00	0.0	36.2	0.033	0.020	36.50	2.00	565.00	56.22	18.25	10.00	0.055
1.00	1.00	8.9	0.0	0.008	0.010	12.50	0.50	565.50	56.27	25.00	20.00	0.056
1.00	1.00	0.0	36.2	0.033	0.010	26.30	1.50	567.00	56.42	17.53	6.67	0.041
1.00	1.00	8.9	0.0	0.008	0.000	16.70	0.40	567.40	56.46	41.75	0.00	0.045
1.00	1.00	0.0	36.0	0.033	0.040	35.90	1.60	569.00	56.62	22.44	25.00	0.044
1.00	1.00	8.9	0.0	0.008	0.050	38.60	1.50	570.50	56.77	25.73	33.33	0.168
1.00	1.00	0.0	37.2	0.034	0.020	20.00	0.50	571.00	56.82	40.00	40.00	0.013
1.00	1.00	9.4	0.0	0.009	0.000	4.00	0.10	571.10	56.83	40.00	0.00	0.011
1.00	1.00	0.0	36.9	0.034	0.070	18.00	1.90	573.00	57.01	9.47	36.84	0.051
1.00	1.00	8.9	0.0	0.008	0.030	21.70	1.60	574.60	57.17	13.56	18.75	0.179
1.00	1.00	0.0	37.0	0.034	0.050	50.10	1.90	576.50	57.36	26.37	26.32	0.051
1.00	1.00	9.0	0.0	0.008	0.010	15.70	0.40	576.90	57.40	39.25	25.00	0.044
1.00	1.00	0.0	38.0	0.035	0.150	20.50	2.90	579.80	57.69	7.07	51.72	0.076
1.00	1.00	0.0	262.2	0.240	0.210	222.00	14.00	593.80	59.08	15.86	15.00	0.053
1.00	1.00	0.0	185.5	0.170	0.300	192.50	23.50	617.30	61.42	8.19	12.77	0.127
0.01	0.01	0.0	0.0	0.000	4.010	138.00	62.50	679.80	67.64	2.21	64.16	

TABLE A44

RESULTS OF RUN LC44

[2.26 WF => 0.2 RHPV CO2 @ 1.0 MPa (0.039 g-mol) 4:1 WAG, 10 Slugs, LIVE OIL]

Porosity [%] = 35.1
Oil Viscosity [mPa.s] = 1046.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 7.56

Pore Volume [cm3] = 1092.0
Initial Oil Saturation [%] = 44.1
Hydrocarbon Pore Volume [cm3] = 449.0
Carbon Dioxide Retention [%inj] = *****

Connate Water Saturation [%] = 58.9
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 10.4500
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	1.00	8.9	0.0	0.008	0.010	19.00	1.00	1.00	0.22	19.00	10.00	0.112
1.00	1.00	0.0	36.0	0.033	0.010	28.00	1.60	2.60	0.58	17.50	6.25	0.044
1.00	1.00	8.9	0.0	0.008	0.010	32.00	1.00	3.60	0.80	32.00	10.00	0.112
1.00	1.00	0.0	36.0	0.033	0.010	9.99	0.10	3.70	0.82	99.90	100.00	0.003
1.00	1.00	8.9	0.0	0.008	0.010	32.60	1.20	4.90	1.09	27.17	8.33	0.134
1.00	1.00	0.0	37.0	0.034	0.010	17.00	1.00	5.90	1.31	17.00	10.00	0.027
1.00	1.00	8.9	0.0	0.008	0.010	35.00	1.10	7.00	1.56	31.82	9.09	0.123
1.00	1.00	0.0	36.2	0.033	0.020	36.50	2.00	9.00	2.00	18.25	10.00	0.055
1.00	1.00	8.9	0.0	0.008	0.010	12.50	0.50	9.50	2.12	25.00	20.00	0.056
1.00	1.00	0.0	36.2	0.033	0.010	26.30	1.50	11.00	2.45	17.53	6.67	0.041
1.00	1.00	8.9	0.0	0.008	0.000	16.70	0.40	11.40	2.54	41.75	0.00	0.045
1.00	1.00	0.0	36.0	0.033	0.040	35.90	1.60	13.00	2.90	22.44	25.00	0.044
1.00	1.00	8.9	0.0	0.008	0.050	38.60	1.50	14.50	3.23	25.73	33.33	0.168
1.00	1.00	0.0	37.2	0.034	0.020	20.00	0.50	15.00	3.34	40.00	40.00	0.013
1.00	1.00	9.4	0.0	0.009	0.000	4.00	0.10	15.10	3.36	40.00	0.00	0.011
1.00	1.00	0.0	36.9	0.034	0.070	18.00	1.90	17.00	3.79	9.47	36.84	0.051
1.00	1.00	8.9	0.0	0.008	0.030	21.70	1.60	18.60	4.14	13.56	18.75	0.179

TABLE A44 (CONTINUED)

RESULTS OF RUN LC44
[2.26 WF => 0.2 RHPV CO2 @ 1.0 MPa (0.039 g-mol) 4:1 WAG, 10 Slugs, LIVE OIL]

Porosity [%] = 35.1
Oil Viscosity [mPa.s] = 1046.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 7.56

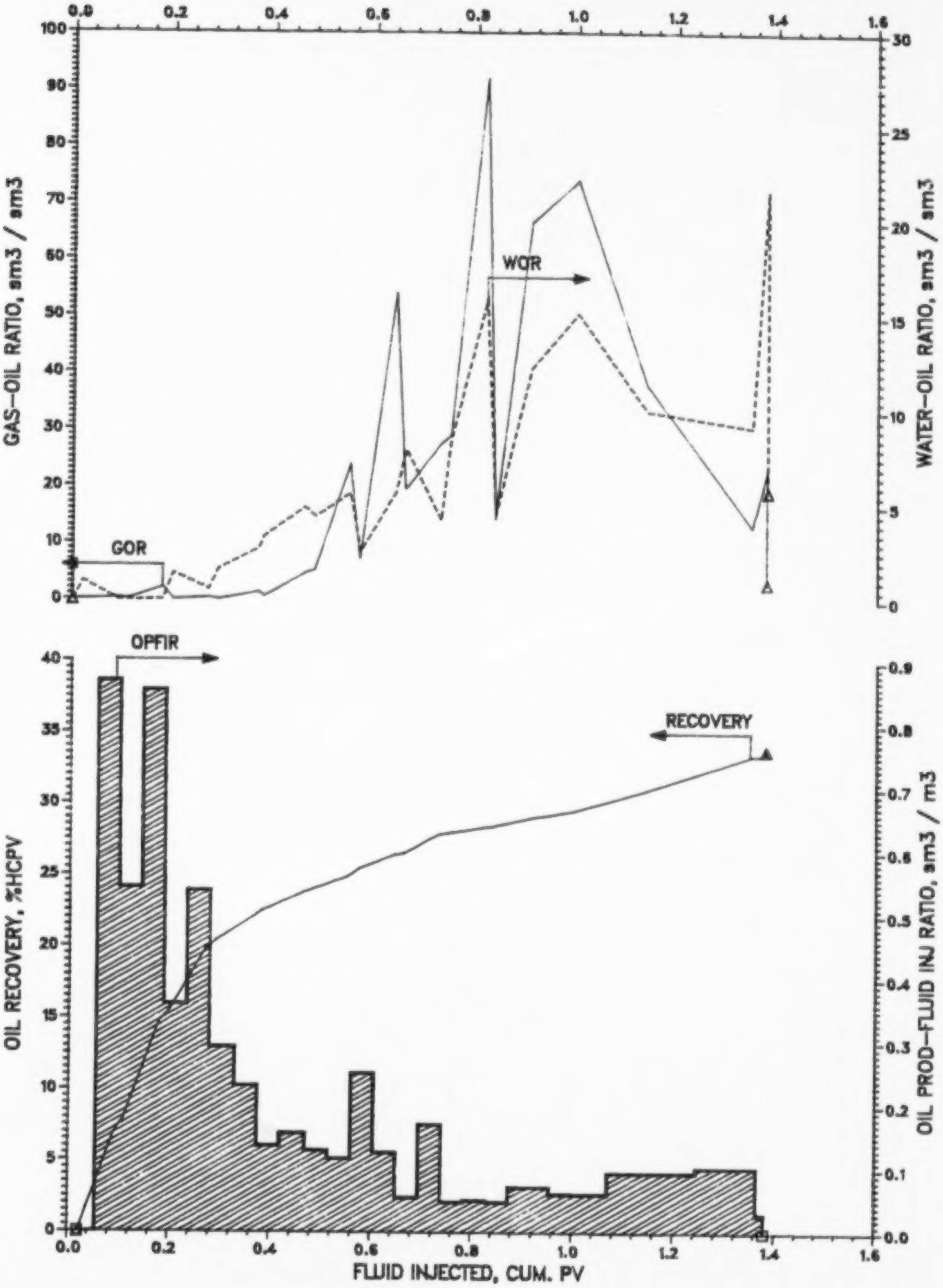
Pore Volume [cm3] = 1092.0
Initial Oil Saturation [%] = 44.1
Hydrocarbon Pore Volume [cm3] = 449.0
Carbon Dioxide Retention [%inj] = *****

Connate Water Saturation [%] = 58.9
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 10.4500
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.00	1.00	0.0	37.0	0.034	0.050	50.10	1.90	20.50	4.57	26.37	26.32	0.051
1.00	1.00	9.0	0.0	0.008	0.010	15.70	0.40	20.90	4.65	39.25	25.00	0.044
1.00	1.00	0.0	38.0	0.035	0.150	20.50	2.90	23.80	5.30	7.07	51.72	0.076
1.00	1.00	0.0	262.2	0.240	0.210	222.00	14.00	37.80	8.42	15.86	15.00	0.053
1.00	1.00	0.0	185.5	0.170	0.300	192.50	23.50	61.30	13.65	8.19	12.77	0.127
0.01	0.01	0.0	0.0	0.000	4.010	138.00	62.50	123.80	27.57	2.21	64.16	

Appendix D

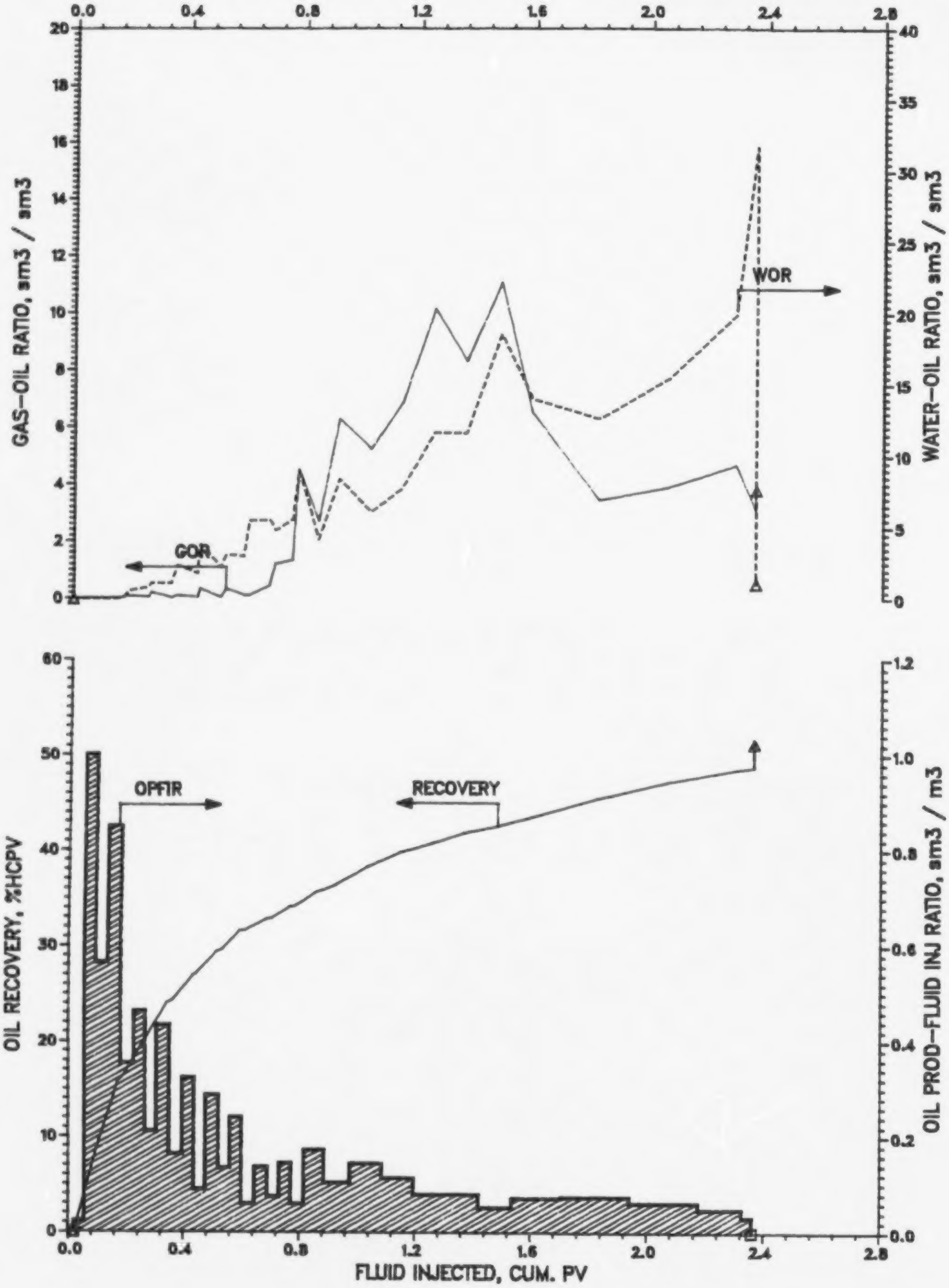
This section contains the production history figures of a few referenced experiments.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 1.550 m/d, μ_o = 1115.0 mPa.s
ϕ = 41.57 %, k = 13.940 darcies, S_o = 91.32 %, S_{wc} = 8.68 %

[0.20 HCPV CO2 @ 2.5 MPa (0.445 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

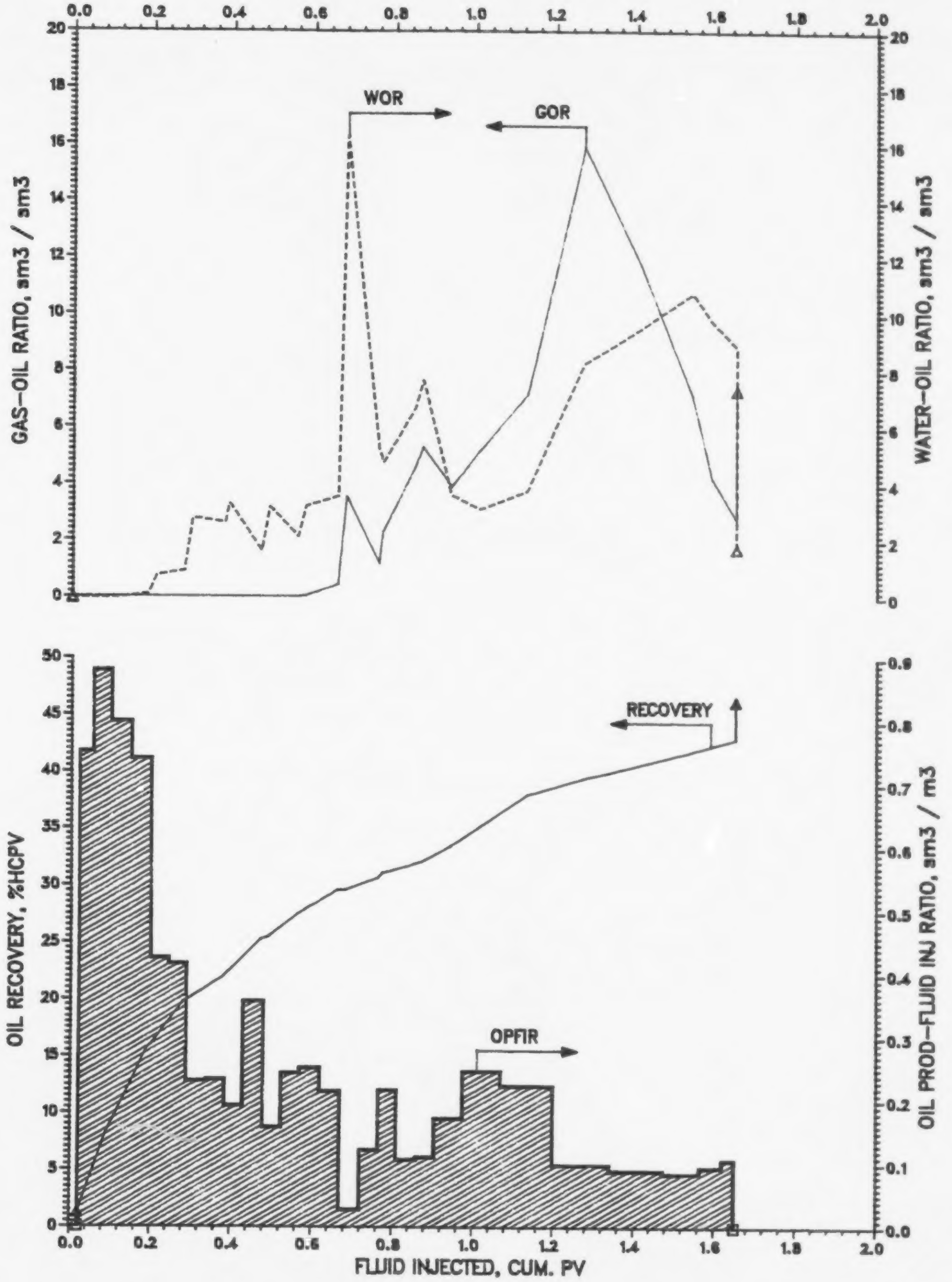
Figure D1: Production History of Run GTD 2.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1175.0 mPa.s
ϕ = 42.08 %, k = 14.520 darcies, S_o = 84.94 %, S_{wc} = 15.06 %

[0.20 HCPV CO2 @ 1.0 MPa (0.151 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

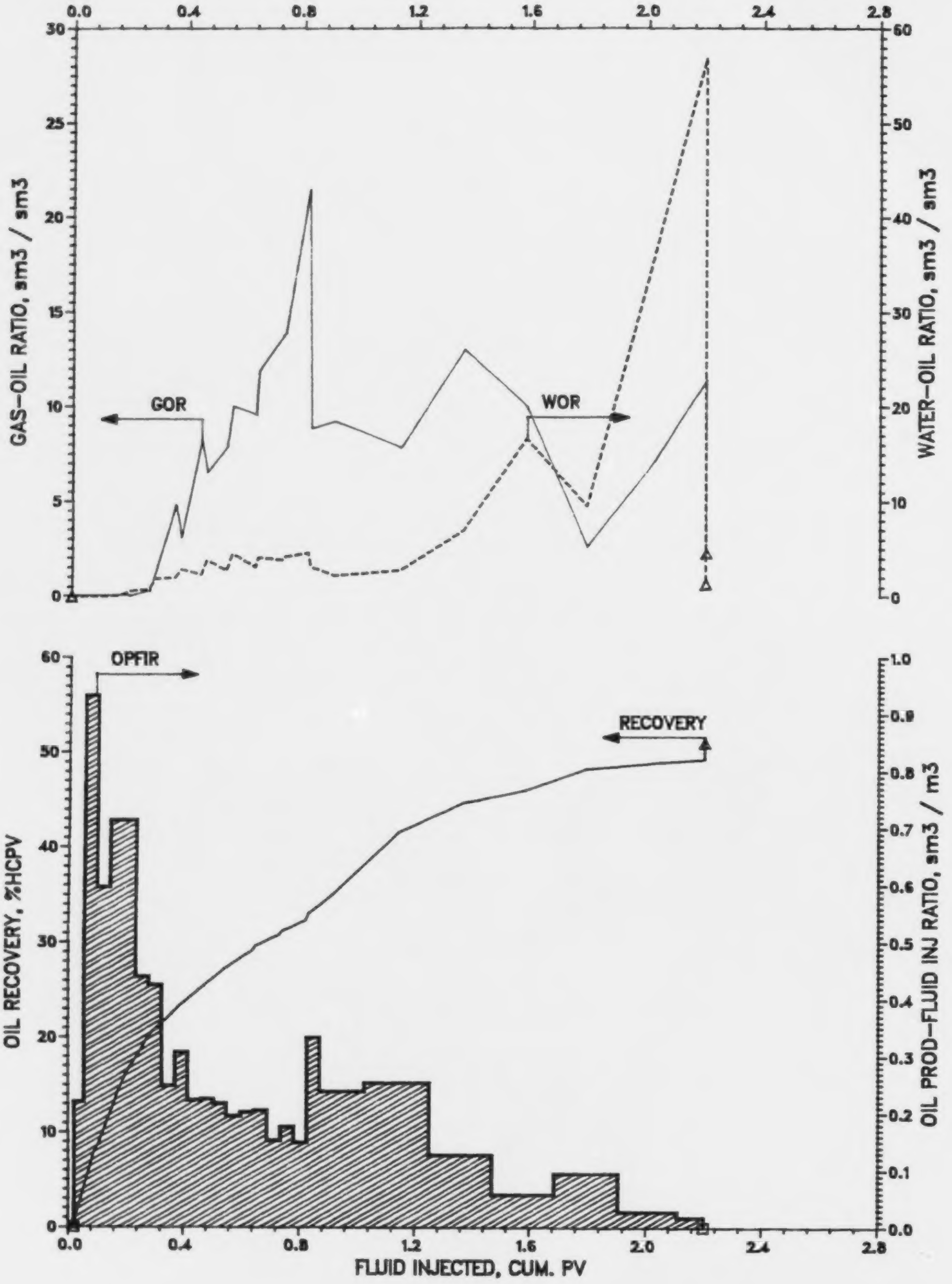
Figure D2: Production History of Run GTD 6.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 1.290 m/d, μ_o = 1046.1 mPa.s
ϕ = 37.85 %, k = 14.600 darcies, S_o = 95.80 %, S_{wc} = 4.20 %

[0.20 HCPV CO2 @ 1.0 MPa (0.154 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

Figure D3: Production History of Run GTD 9.



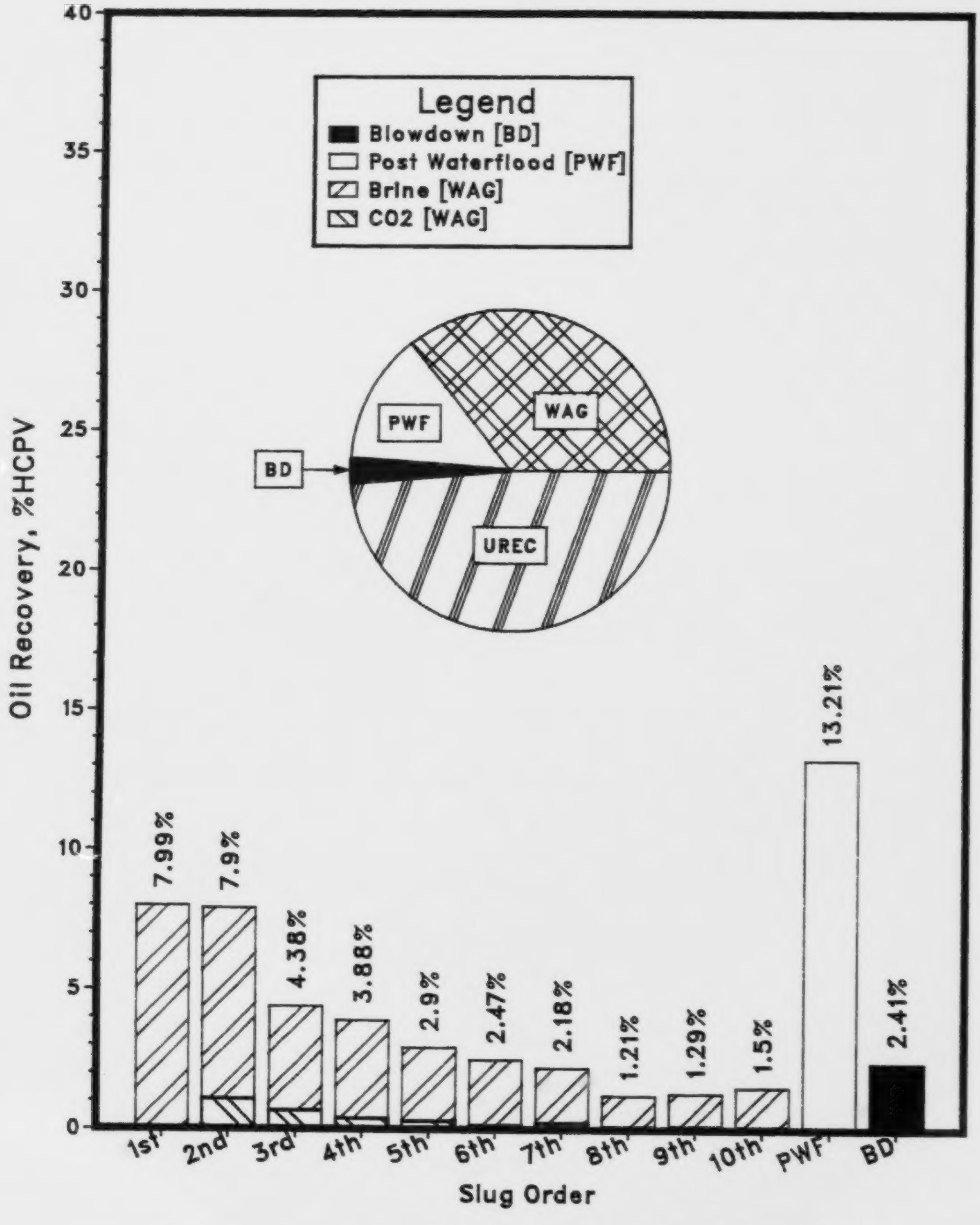
NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s
ϕ = 36.10 %, k = 10.990 darcies, S_o = 90.22 %, S_{wc} = 9.78 %

[0.2 HCPV CO2 @ 1.0 MPa (0.089 g–mol) 4:1 WAG,10 Slugs]

Figure D4: Production History of Run LC 42.

Appendix E

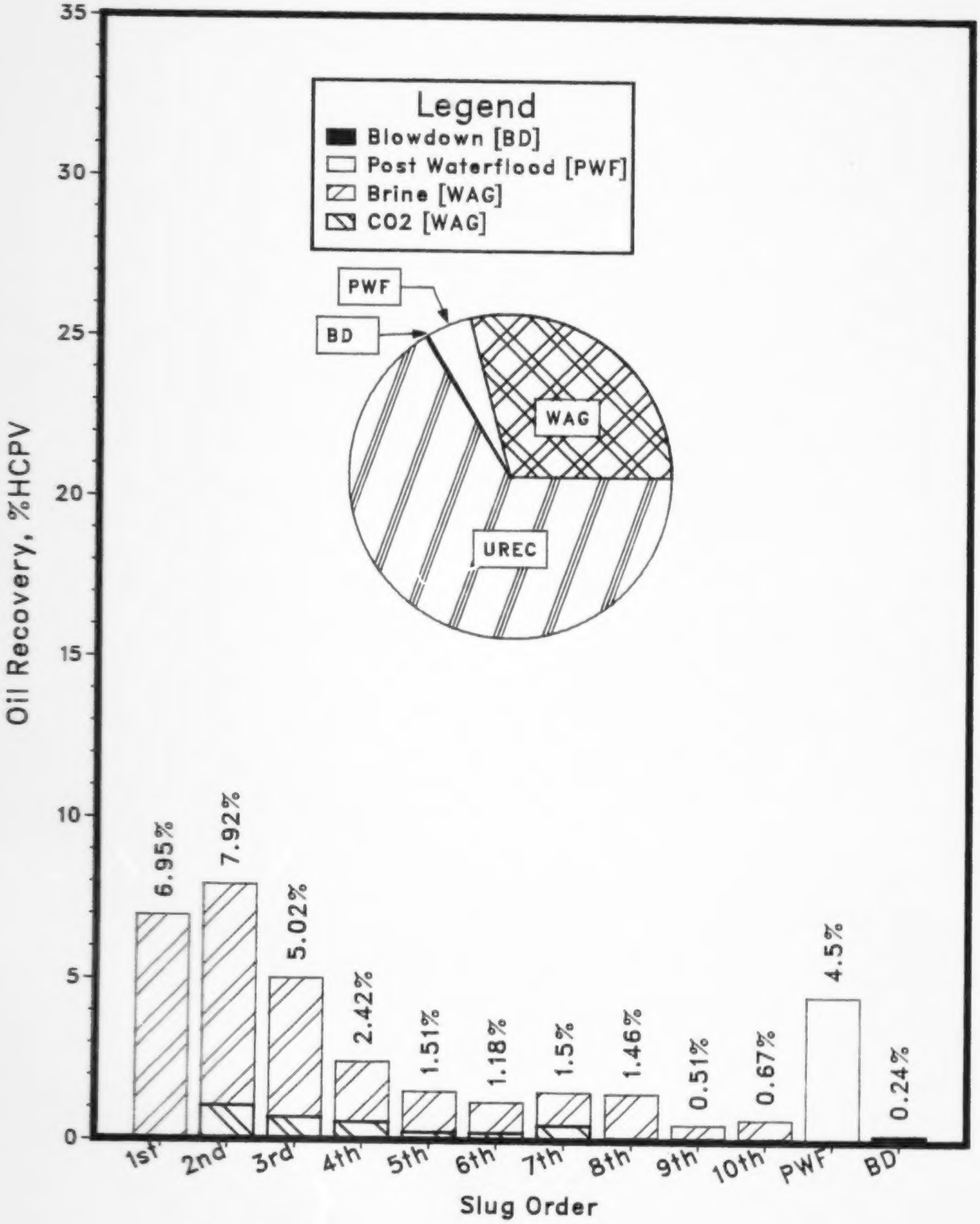
This section contains the oil recovery distribution figures of three experiments (GTD 2,GTD 6, and GTD 9)



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1175.0 mPa.s
ϕ = 42.08 %, k = 14.520 darcies, S_o = 84.94 %, S_{wc} = 15.06 %

[0.20 HCPV CO2 @ 1.0 MPa (0.151 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

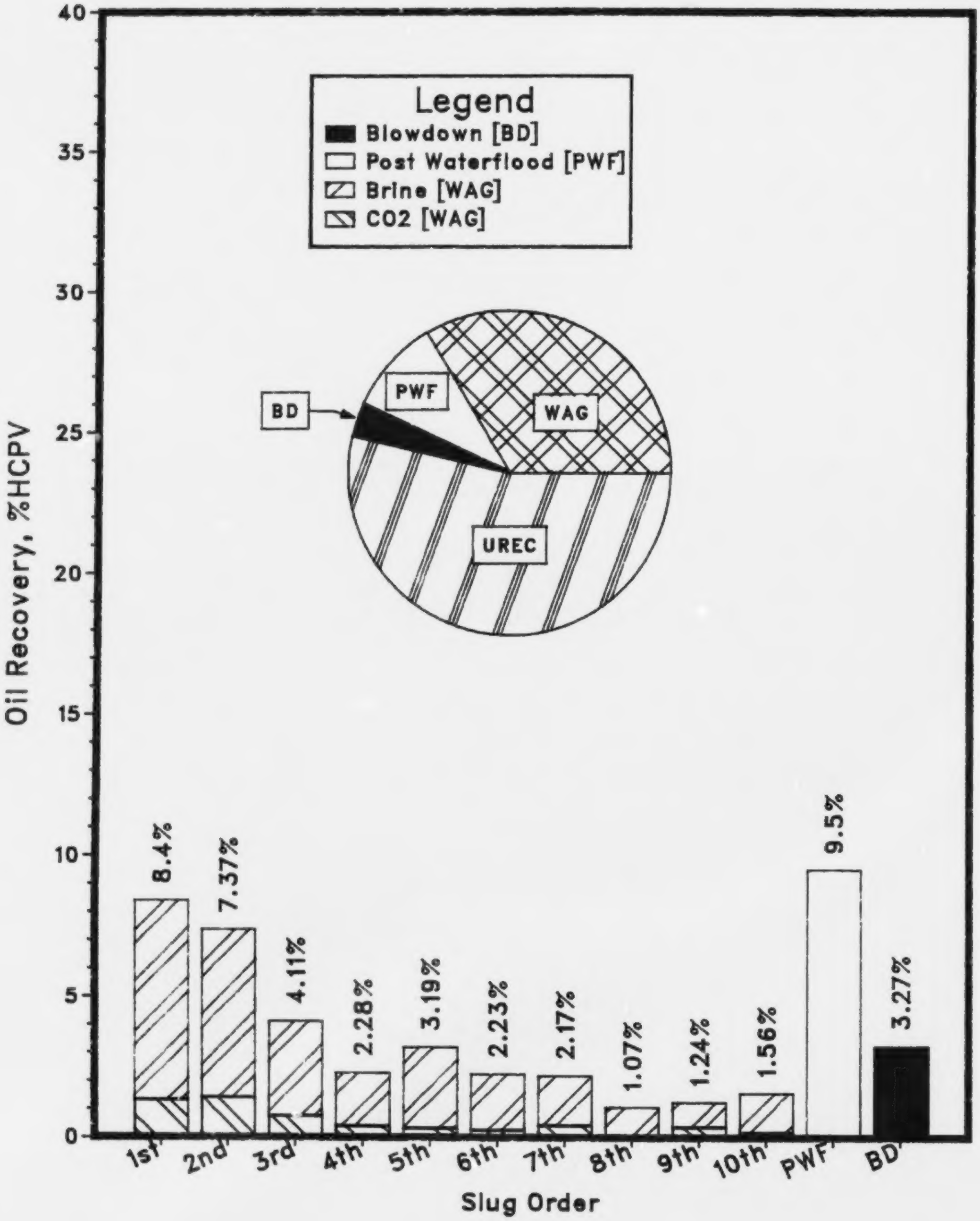
Figure E2: Oil Recovery Distribution of Run GTD 6.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 1.550 m/d, μ_o = 1115.0 mPa.s
ϕ = 41.57 %, k = 13.940 darcies, S_o = 91.32 %, S_{wc} = 8.68 %

[0.20 HCPV CO2 @ 2.5 MPa (0.45 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

Figure E1: Oil Recovery Distribution of Run GTD 2.



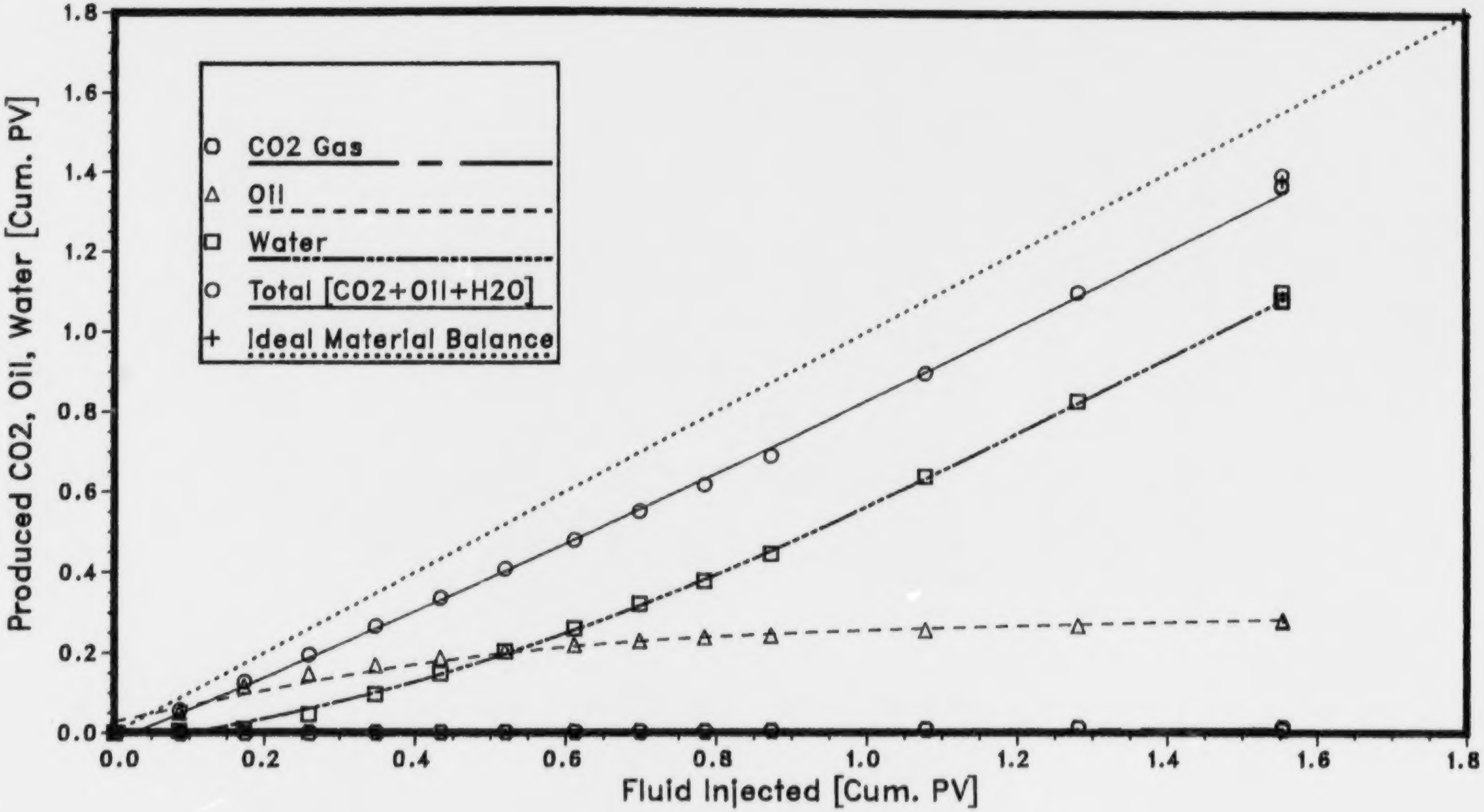
NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 1.290 m/d, μ_o = 1046.1 mPa.s
ϕ = 37.85 %, k = 14.600 darcies, S_o = 95.80 %, S_{wc} = 4.20 %

[0.20 HCPV CO2 @ 1.0 MPa (0.154 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

Figure E3: Oil Recovery Distribution of Run GTD 9.

Appendix F

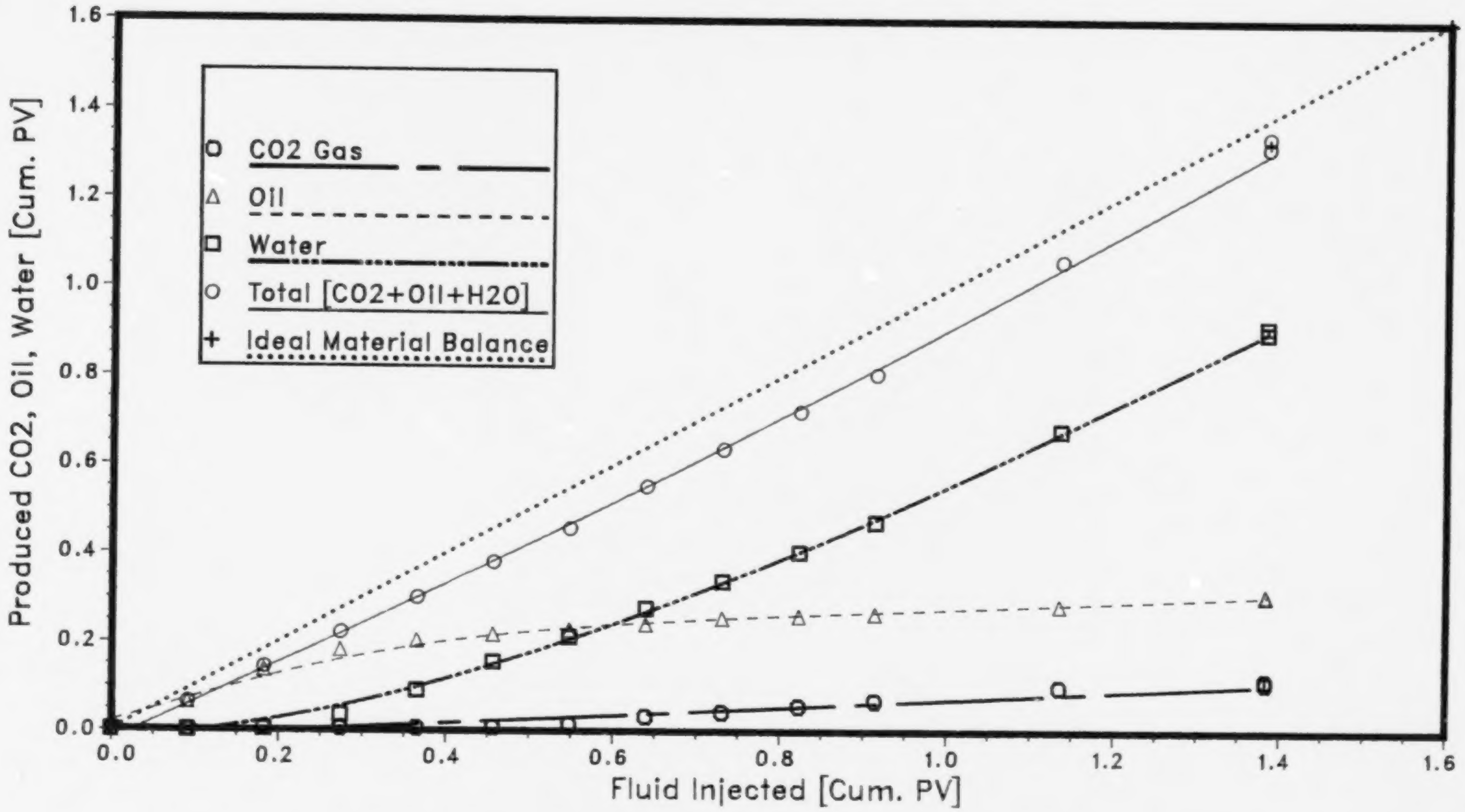
This section contains the figures of the volumetric balance for all the runs.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 1.290 m/d, μ_o = 1230.0 mPa.s
ϕ = 41.55 %, k = 13.080 darcies, S_o = 85.95 %, S_{wc} = 14.05 %

[0.02 HCPV CO2 @ 2.5 MPa (0.42 g–mol) 40:1 WAG, 10–Slugs, 2D Model]

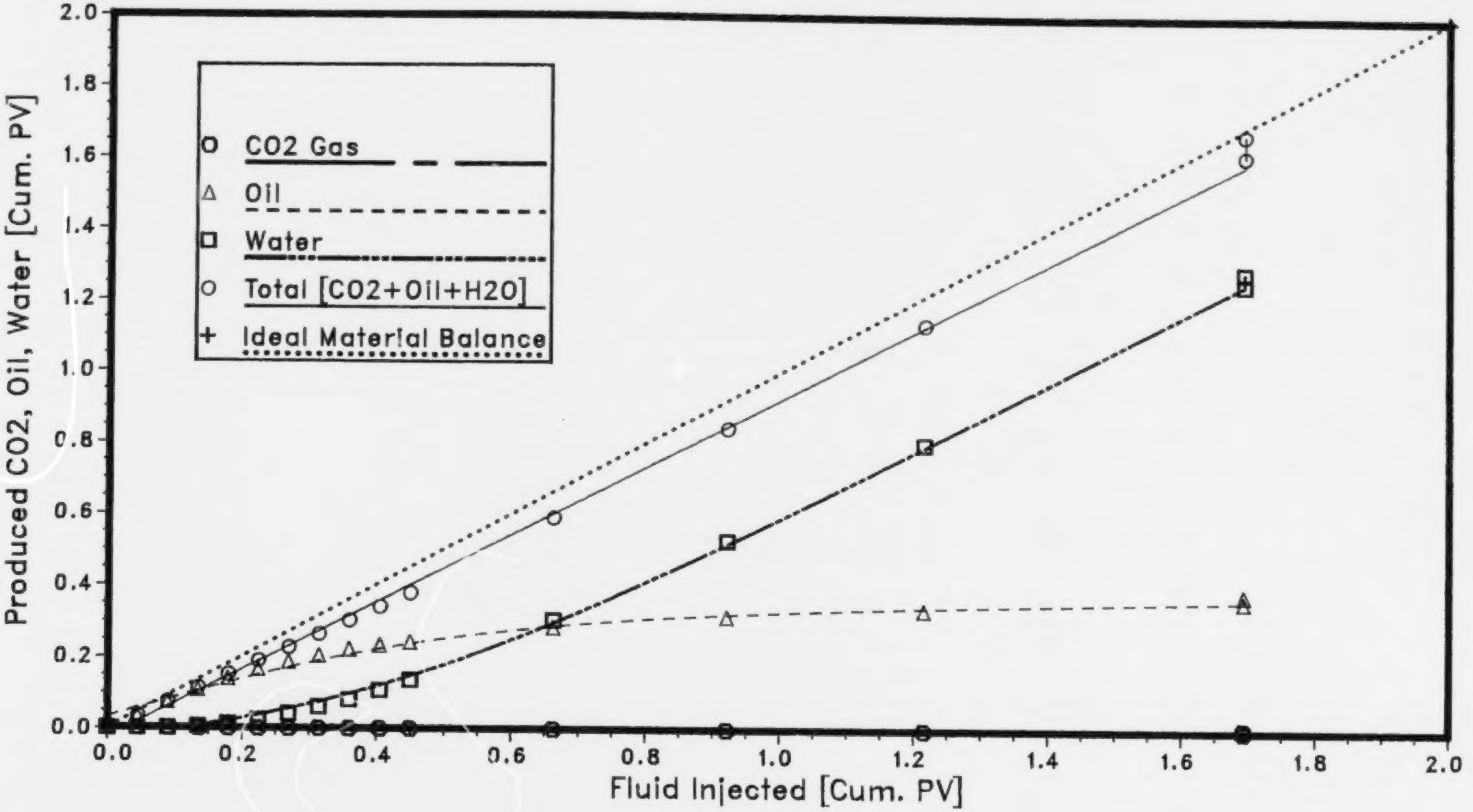
Figure F1: Volumetric Balance on Run GTD 1.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 1.550 m/d, μ_o = 1115.0 mPa.s
ϕ = 41.57 %, k = 13.940 darcies, S_o = 91.32 %, S_{wc} = 8.68 %

[0.20 HCPV CO2 @ 2.5 MPa (0.445 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

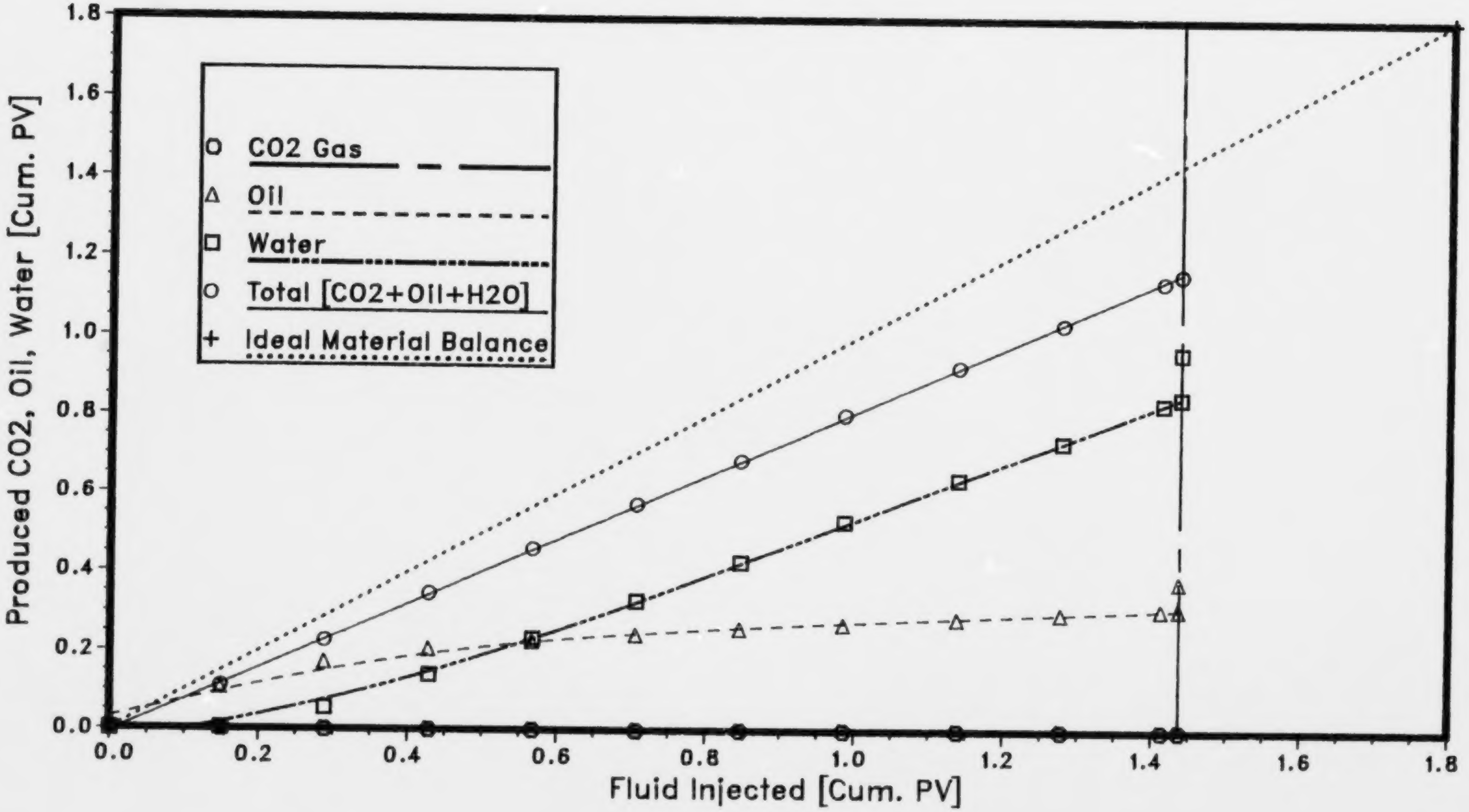
Figure F2: Volumetric Balance on Run GTD 2.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1115.0 mPa.s
ϕ = 41.14 %, k = 18.630 darcies, S_o = 89.60 %, S_{wc} = 10.40 %

[0.10 HCPV CO2 @ 2.5 MPa (0.216 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

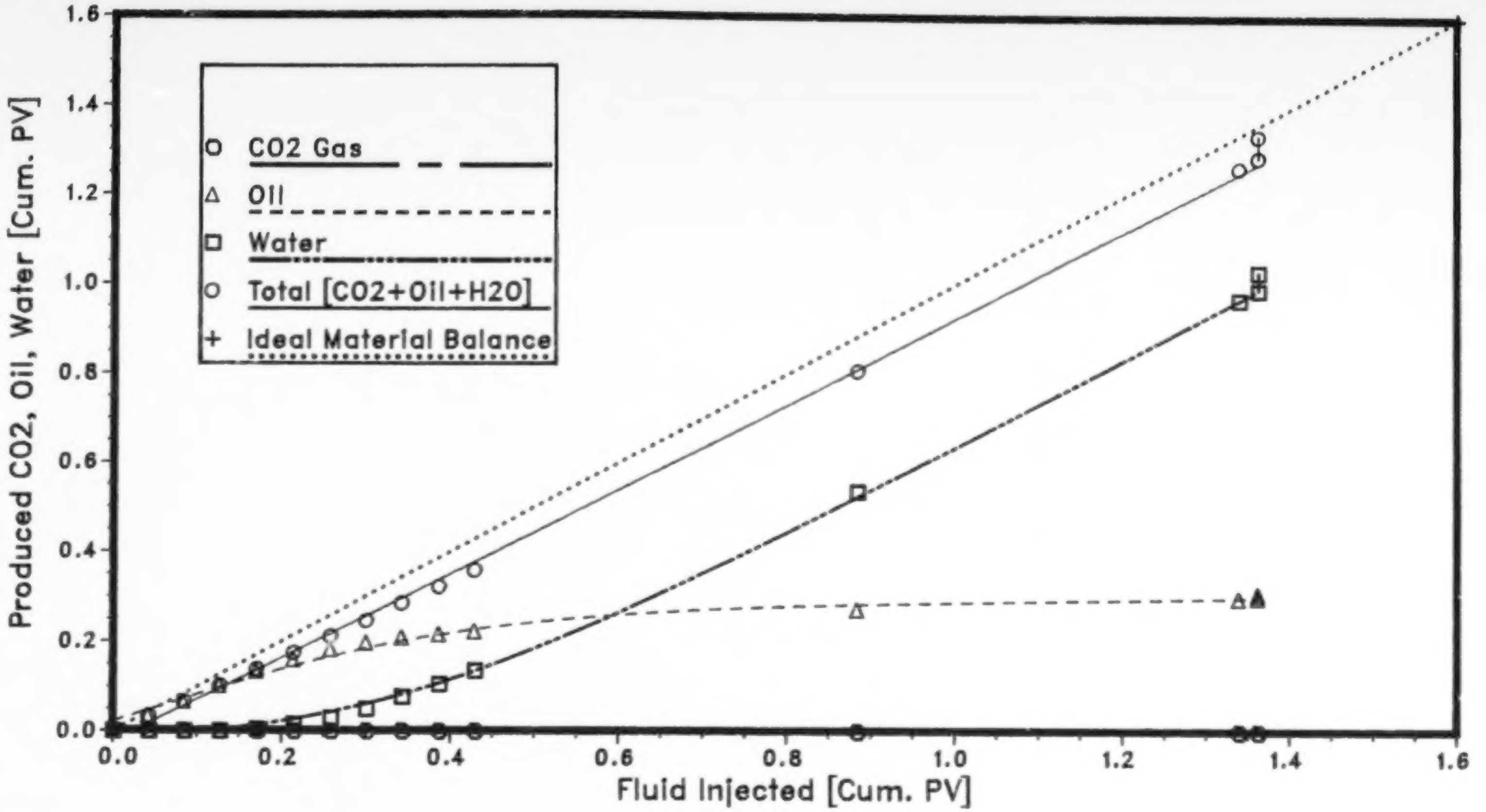
Figure F3: Volumetric Balance on Run GTD 3.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1135.0 mPa.s
$\phi = 41.57$ %, k = 13.570 darcies, $S_o = 93.19$ %, $S_{wc} = 6.81$ %

[0.30 HCPV CO2 @ 2.5 MPa (0.682 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

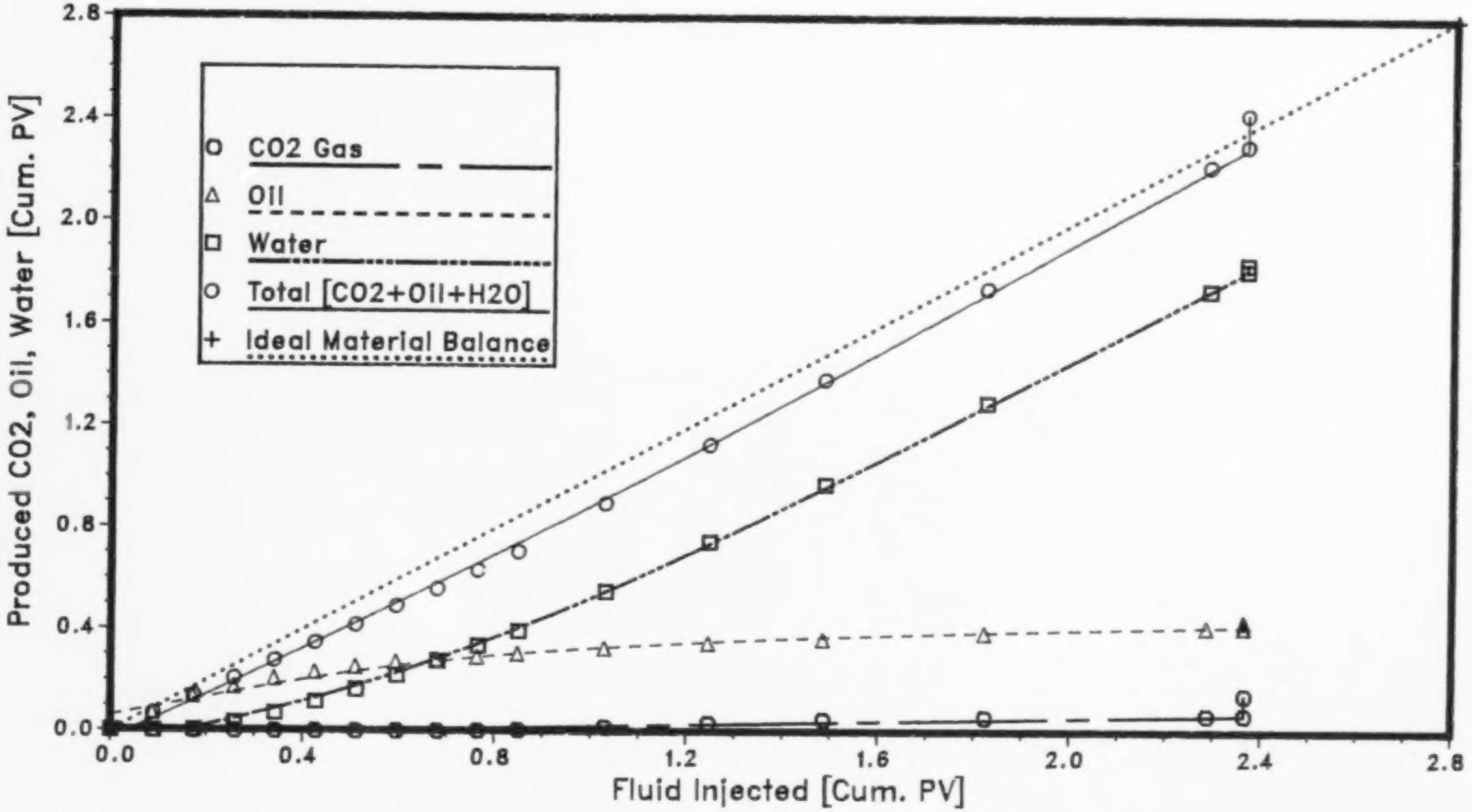
Figure F4: Volumetric Balance on Run GTD 4.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1125.0 mPa.s
ϕ = 43.19 %, k = 11.520 darcies, S_o = 85.61 %, S_{wc} = 14.39 %

[0.10 HCPV CO2 @ 1.0 MPa (0.078 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

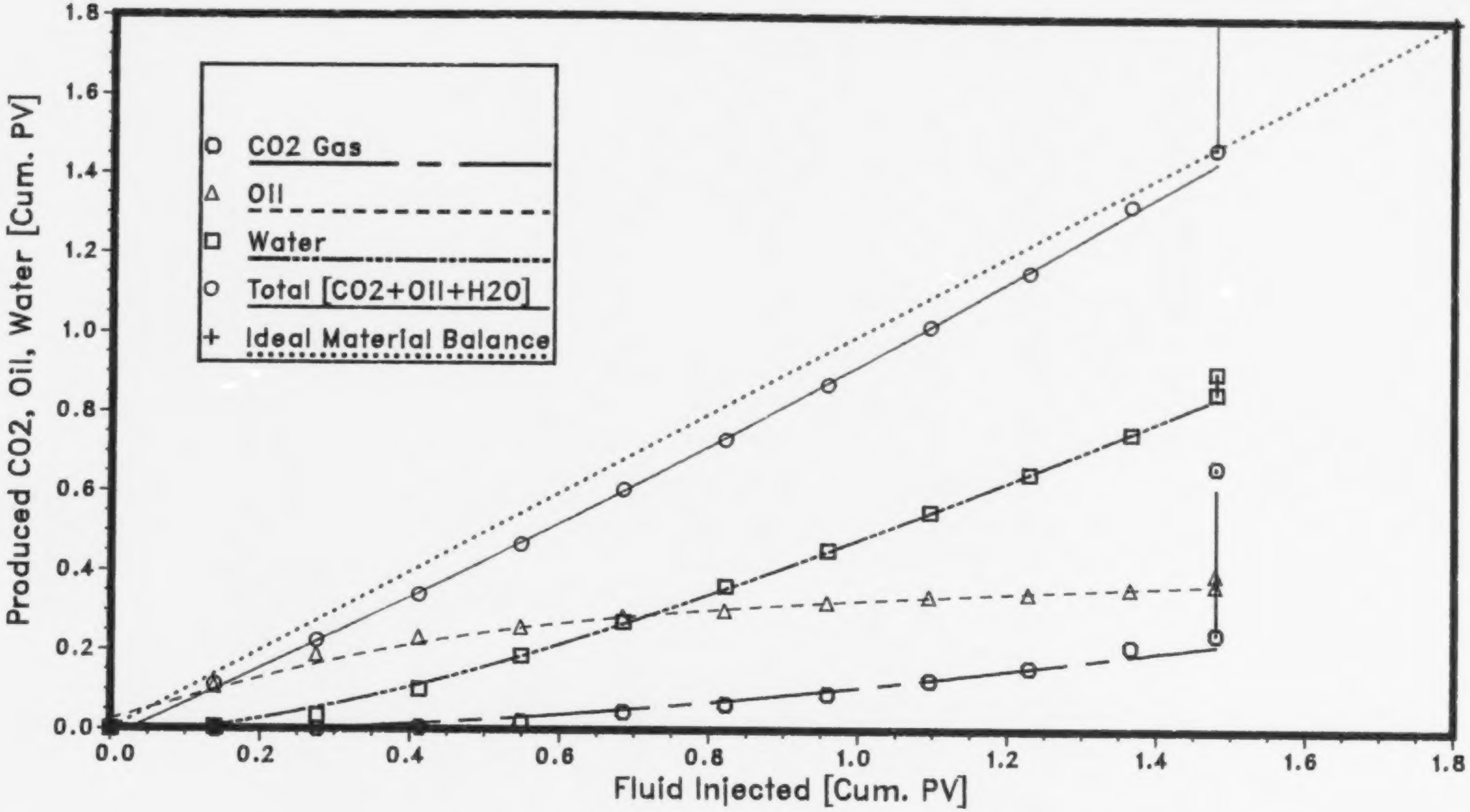
Figure F5: Volumetric Balance on Run GTD 5.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1175.0 mPa.s
ϕ = 42.08 %, k = 14.520 darcies, S_o = 84.94 %, S_{wc} = 15.06 %

[0.20 HCPV CO2 @ 1.0 MPa (0.151 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

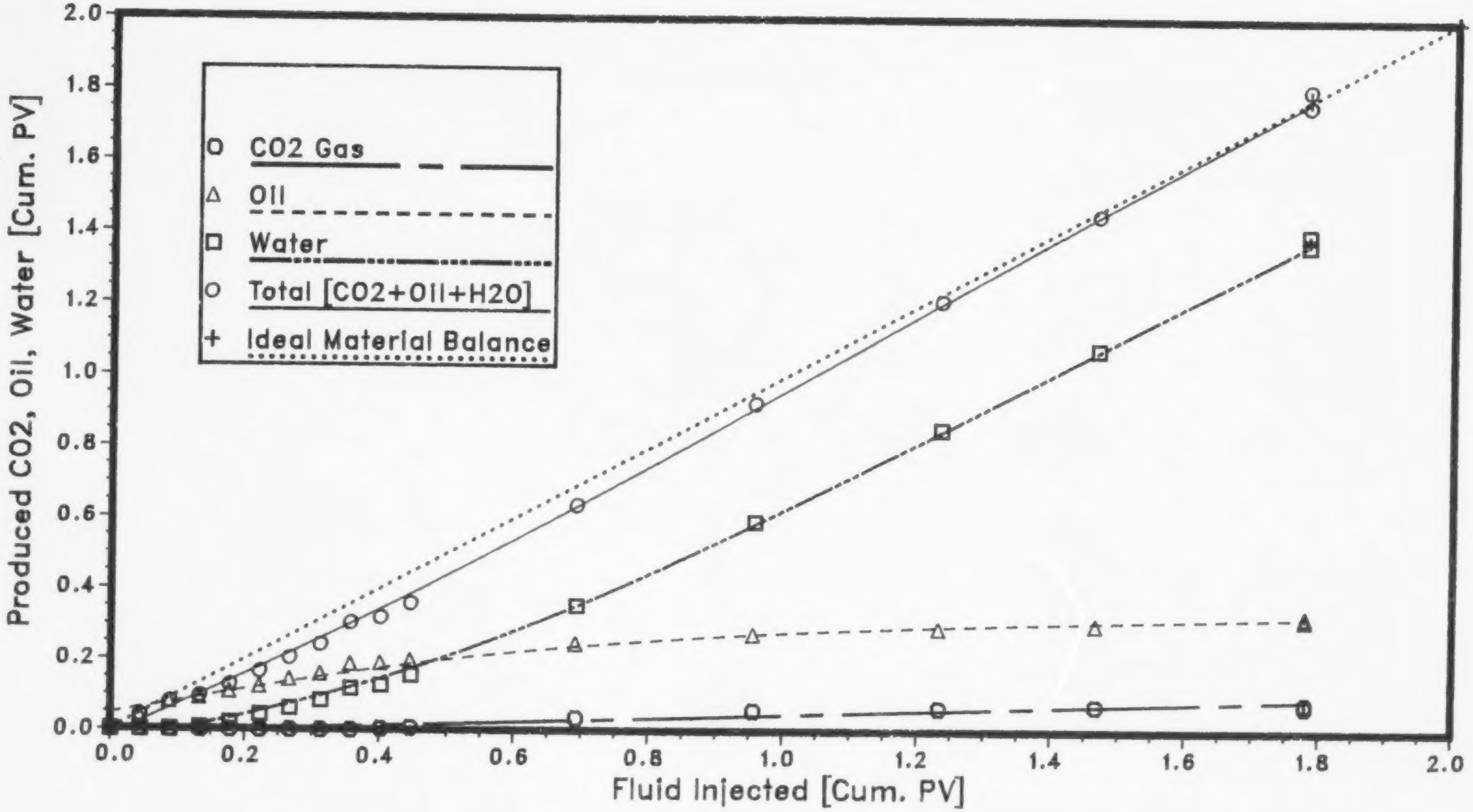
Figure F6: Volumetric Balance on Run GTD 6.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1279.0 mPa.s
ϕ = 37.97 %, k = 15.360 darcies, S_o = 91.05 %, S_{wc} = 8.95 %

[0.30 HCPV CO2 @ 1.0 MPa (0.219 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

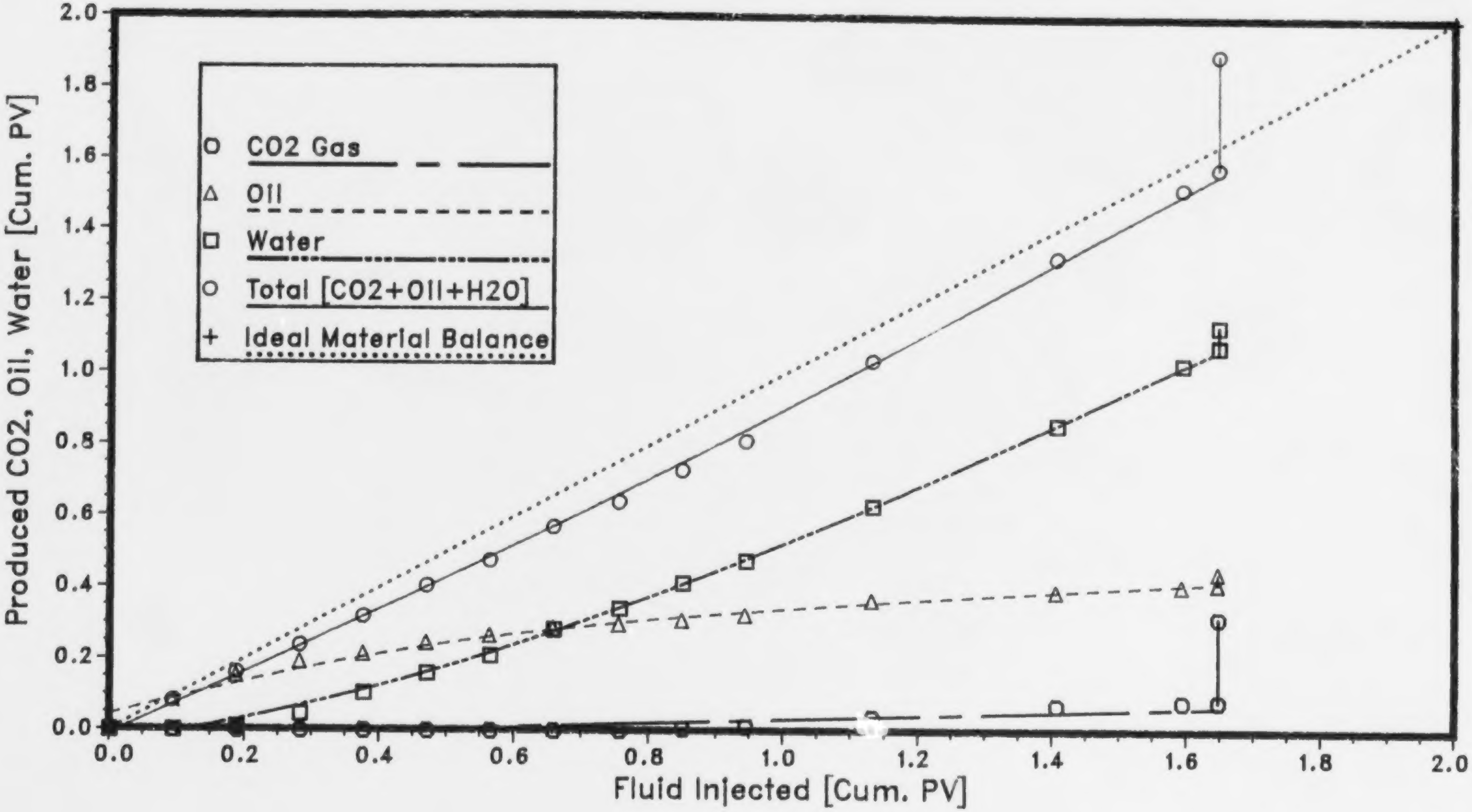
Figure F7: Volumetric Balance on Run GTD 7.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 1.290 m/d, μ_o = 1046.1 mPa.s
ϕ = 37.97 %, k = 15.360 darcies, S_o = 88.85 %, S_{wc} = 11.15 %

[0.10 HCPV CO2 @ 1.0 MPa (0.071 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

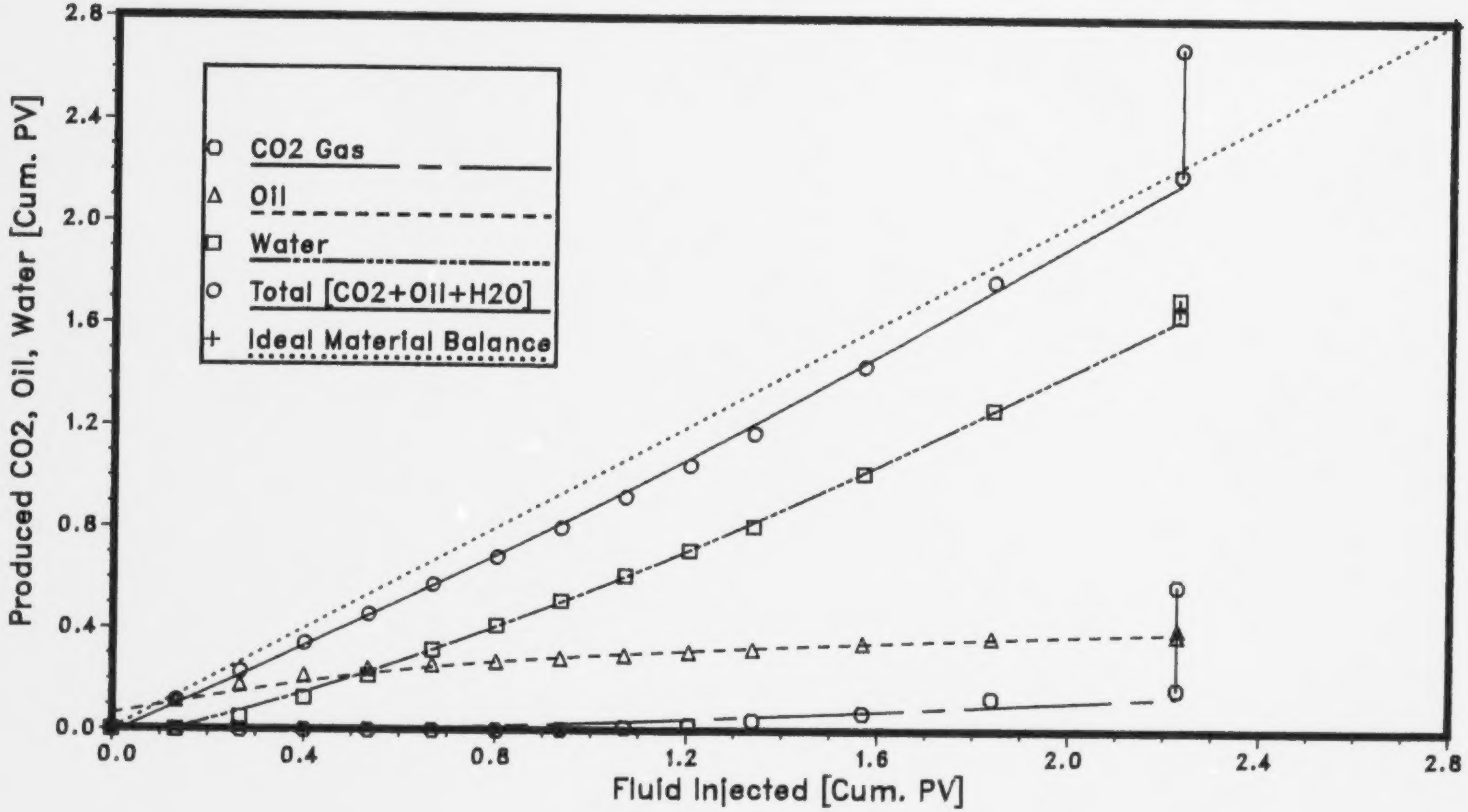
Figure F8: Volumetric Balance on Run GTD 8.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 1.290 m/d, μ_o = 1046.1 mPa.s
ϕ = 37.85 %, k = 14.600 darcies, S_o = 95.80 %, S_{wc} = 4.20 %

[0.20 HCPV CO2 @ 1.0 MPa (0.154 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

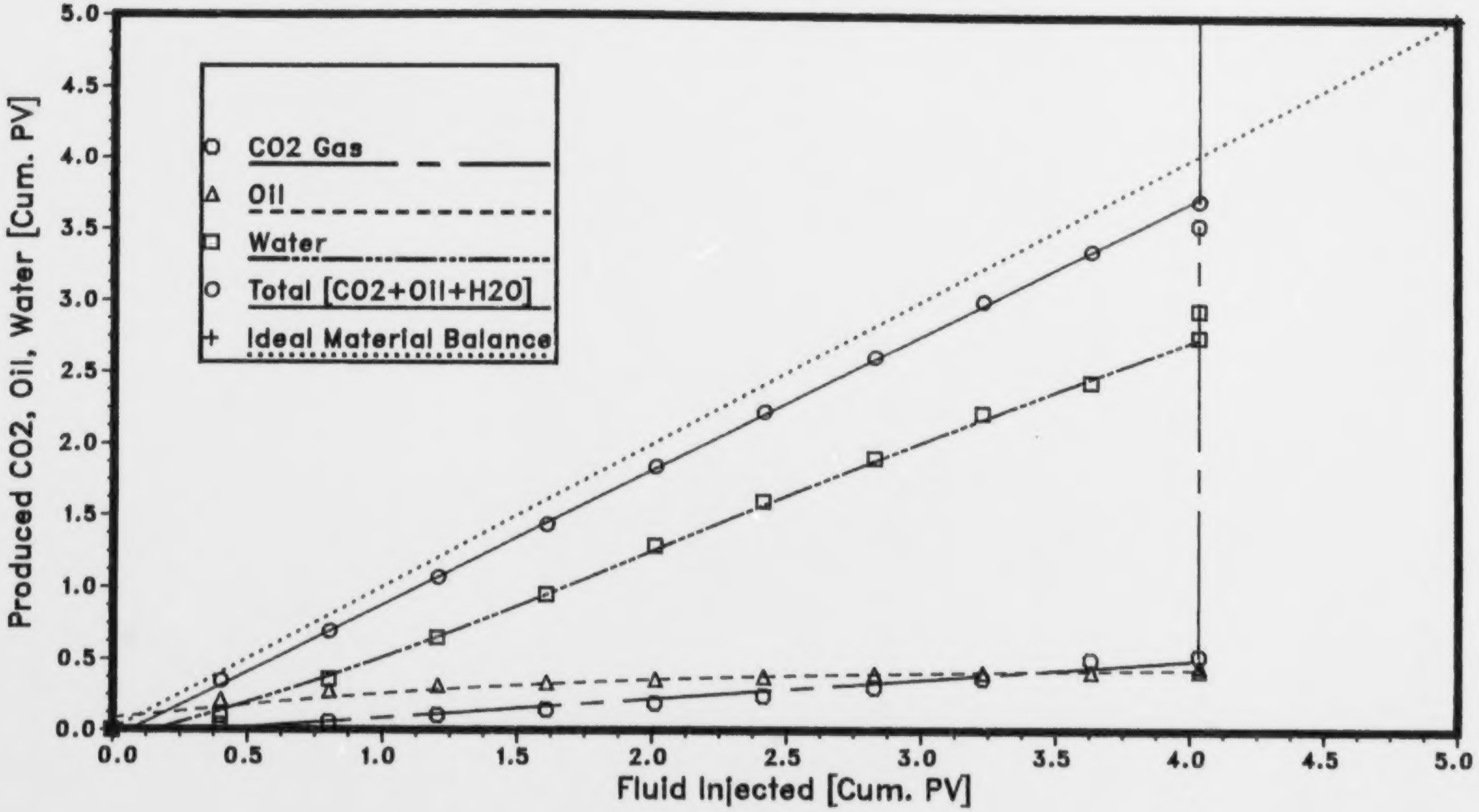
Figure F9: Volumetric Balance on Run GTD 9.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 1.290 m/d, μ_o = 1046.1 mPa.s
ϕ = 29.50 %, k = 12.100 darcies, S_o = 91.70 %, S_{wc} = 8.30 %

[0.30 HCPV CO2 @ 1.0 MPa (0.229 g–mol) 4:1 WAG, 10–Slugs, 2D Model]

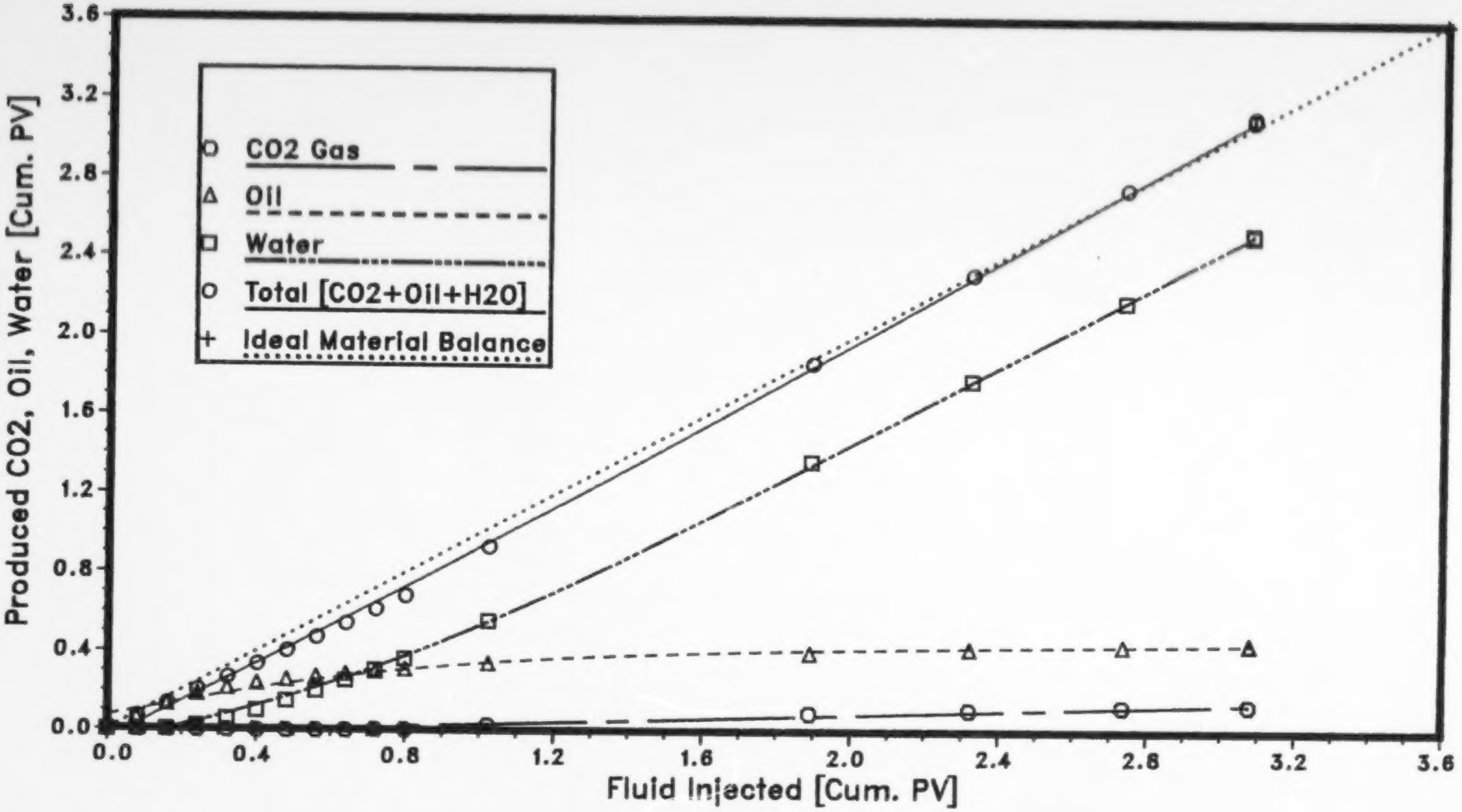
Figure F10: Volumetric Balance on Run GTD 10.



NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 37.63 %, k = 11.350 darcies, S_o = 90.24 %, S_{wc} = 9.76 %

[0.89 HCPV CO2 @ 2.5 MPa (1.13 g–mol) 4:1 WAG, 10–Slugs]

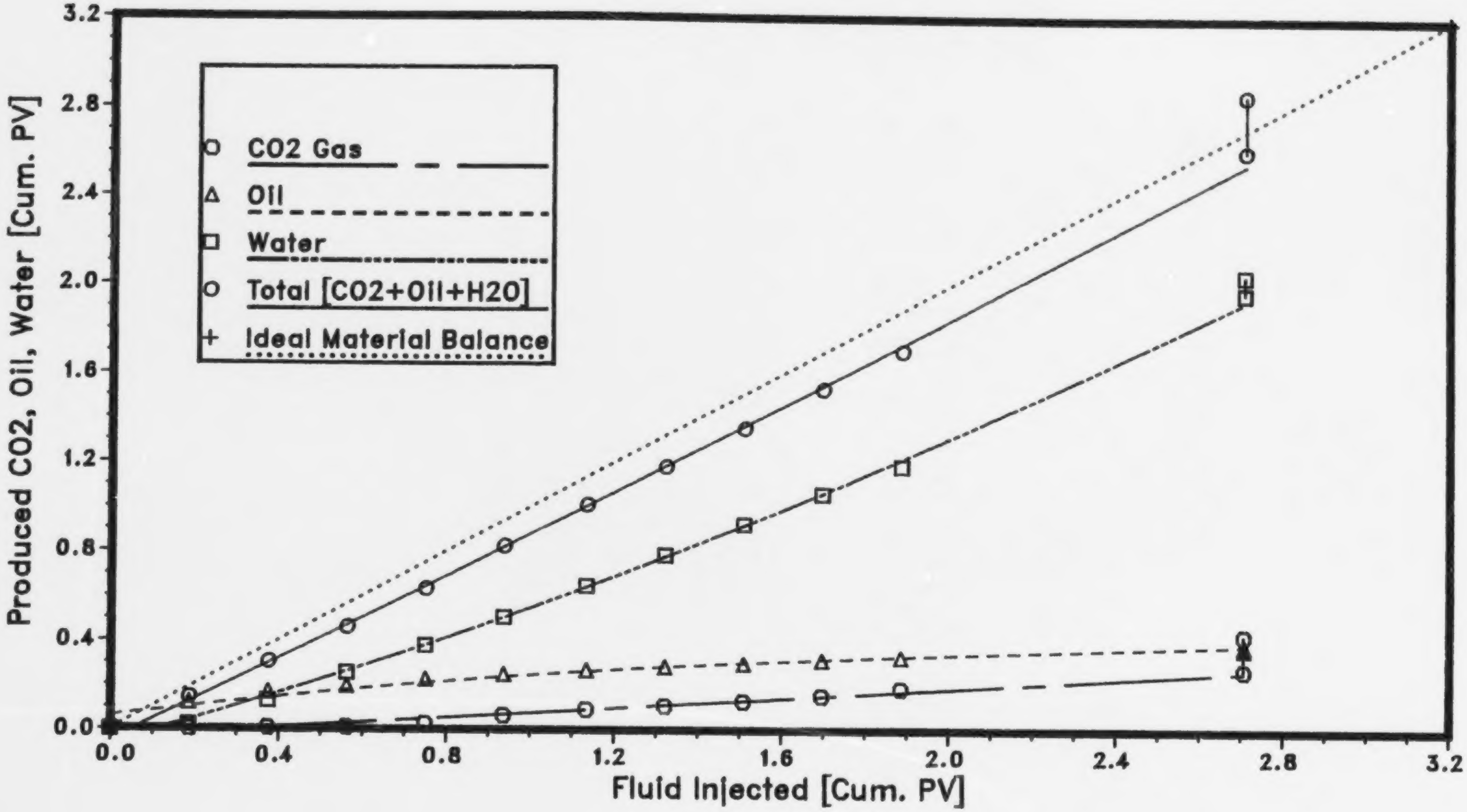
Figure F11: Volumetric Balance on Run LC 30.



NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 36.35 %, k = 11.040 darcies, S_o = 79.35 %, S_{wc} = 20.65 %

[0.20 HCPV CO2 @ 2.5 MPa (0.22 g–mol) 4:1 WAG, 10–Slugs]

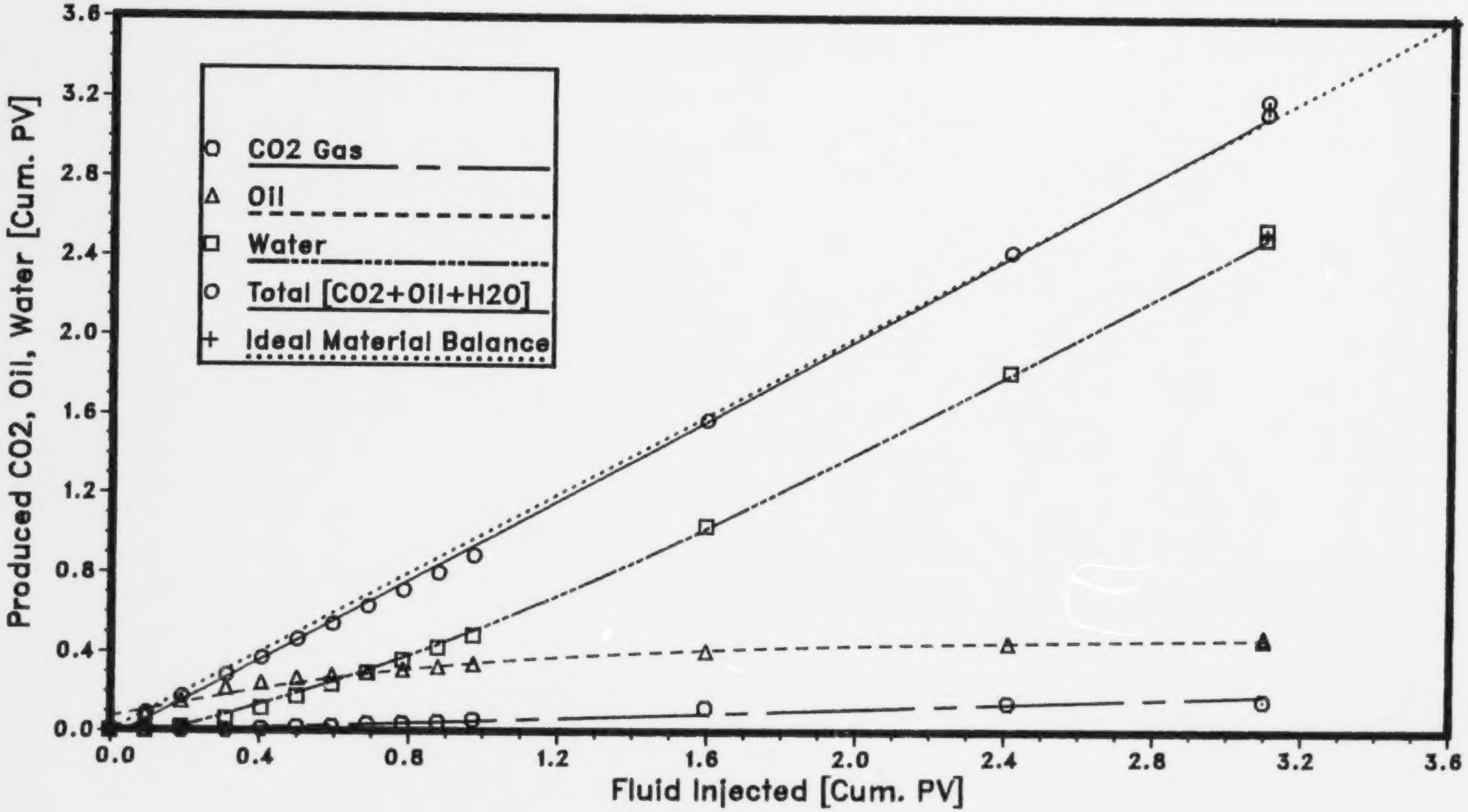
Figure F12: Volumetric Balance on Run LC 31.



NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1055.3 mPa.s
ϕ = 37.63 %, k = 14.130 darcies, S_o = 93.66 %, S_{wc} = 6.34 %

[0.40 HCPV CO2 @ 2.5 MPa (0.53 g–mol) 4:1 WAG, 10–Slugs]

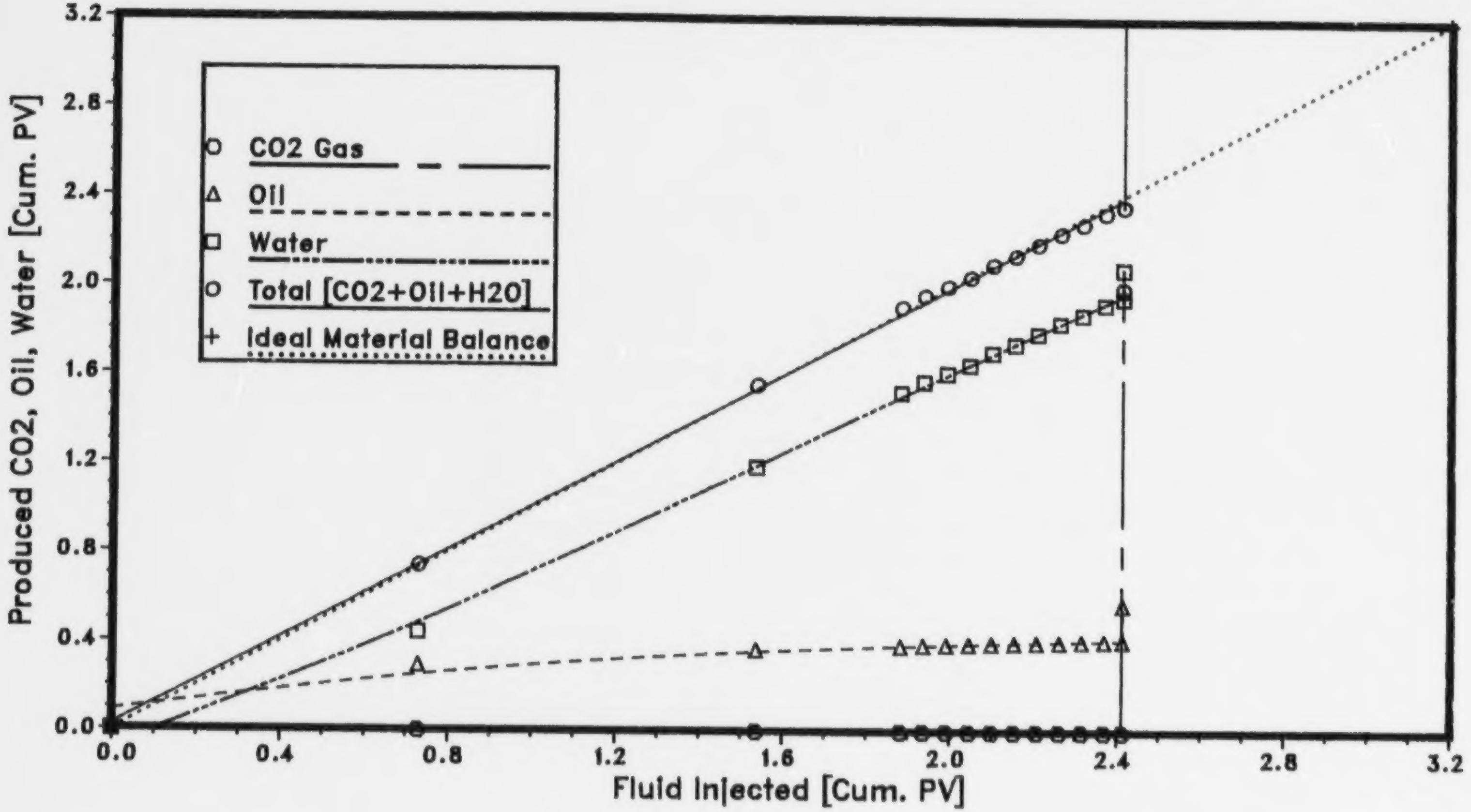
Figure F13: Volumetric Balance on Run LC 32.



NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1230.0 mPa.s
ϕ = 37.44 %, k = 13.080 darcies, S_o = 94.94 %, S_{wc} = 5.06 %

[0.20 HCPV CO2 @ 2.5 MPa (0.22 g–mol) 4:1 WAG, 10–Slugs]

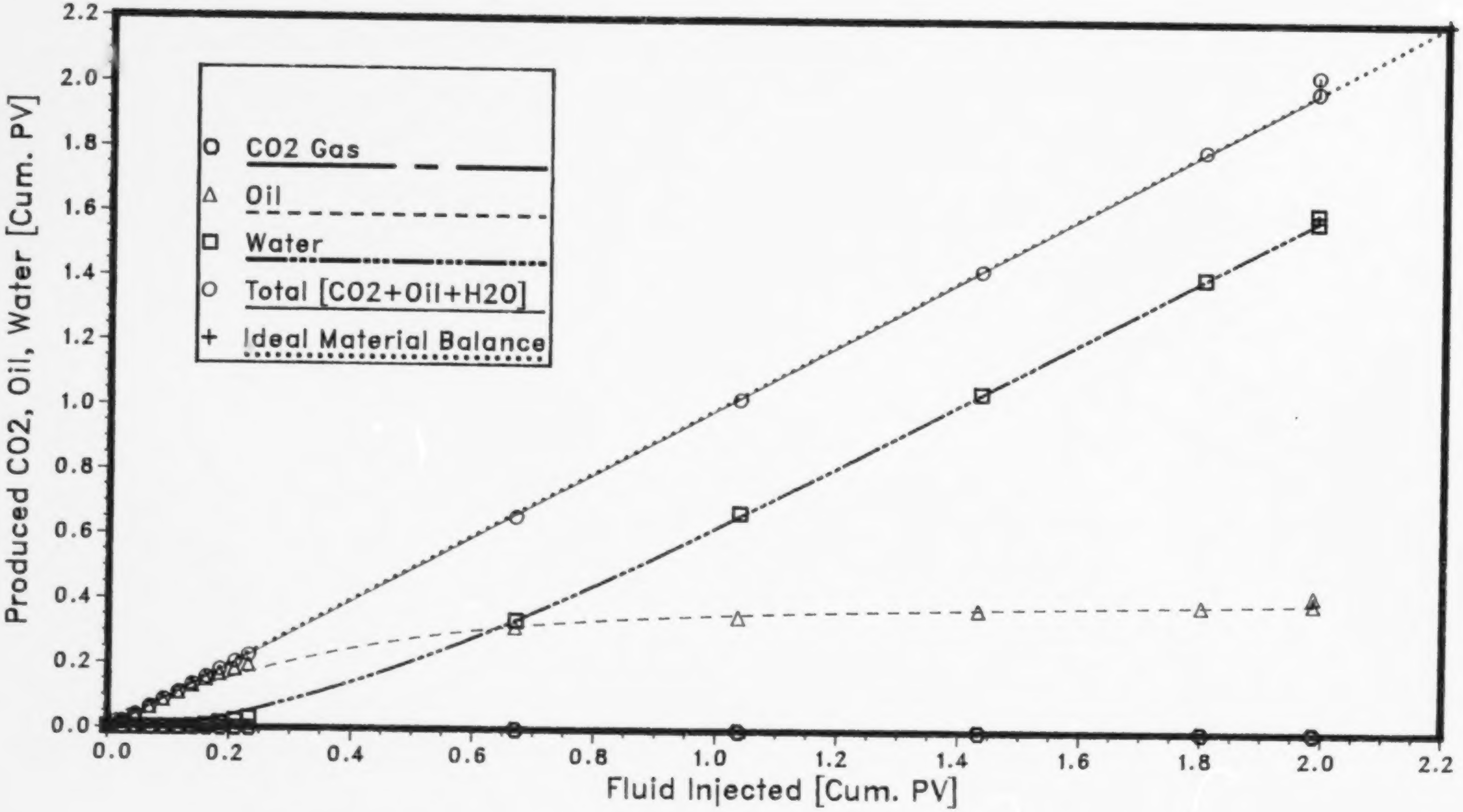
Figure F14: Volumetric Balance on Run LC 33.



NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 882.0 mPa.s
ϕ = 36.47 %, k = 9.910 darcies, S_o = 92.54 %, S_{wc} = 7.46 %

[2.02 HCPV WF=>0.20 RHCPV CO2 @ 2.5MPa (0.24g-mol) 4:1 WAG,10 Slugs]

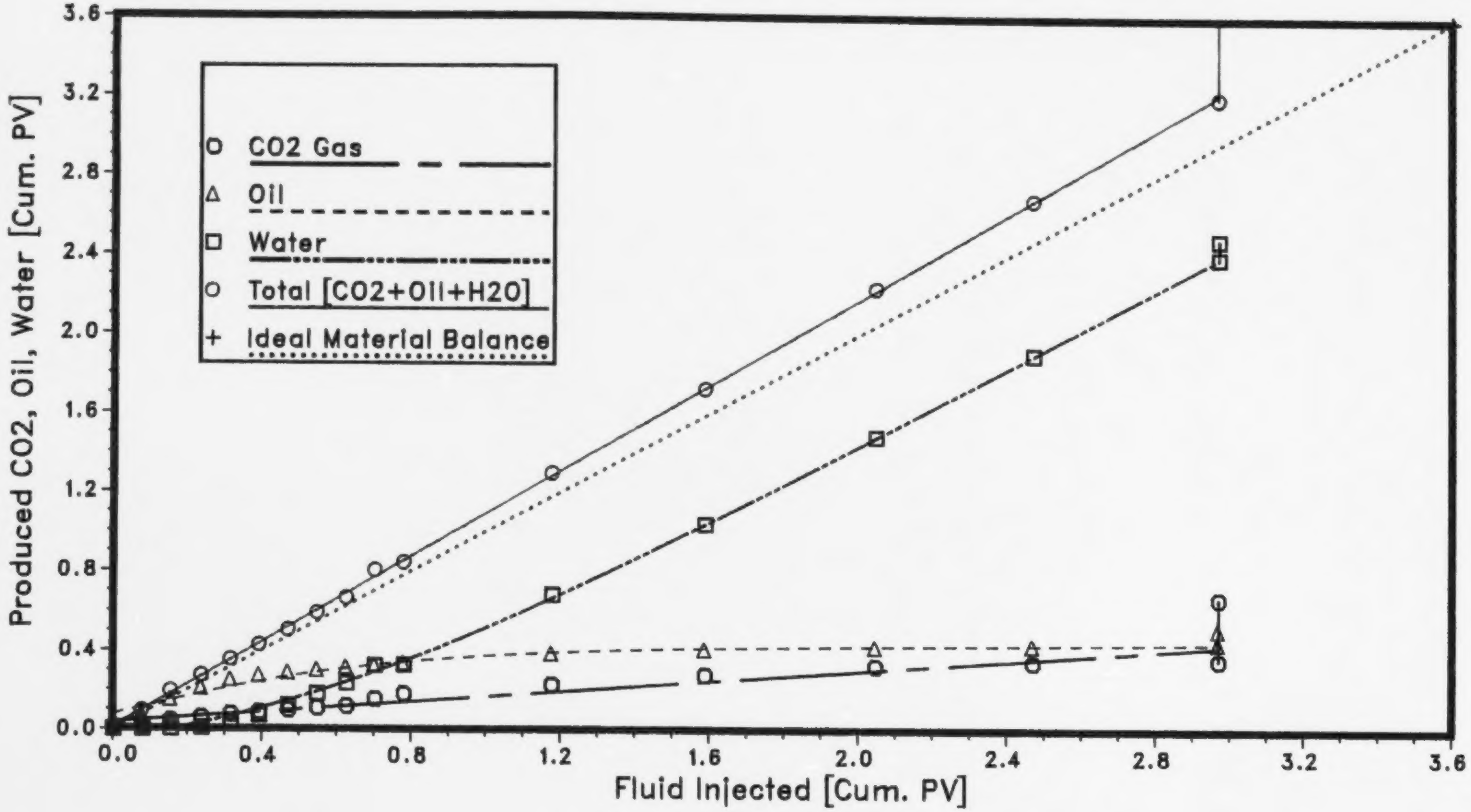
Figure F15: Volumetric Balance on Run LC 34.



NOTE: Average Run Conditions: Direct Line Drive, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1130.0 mPa.s
$\phi = 37.15$ %, k = 11.170 darcies, $S_o = 91.83$ %, $S_{wc} = 8.17$ %

[0.05 HCPV CO2 @ 2.5MPa (0.064g–mol) 4:1 WAG,10 Slugs]

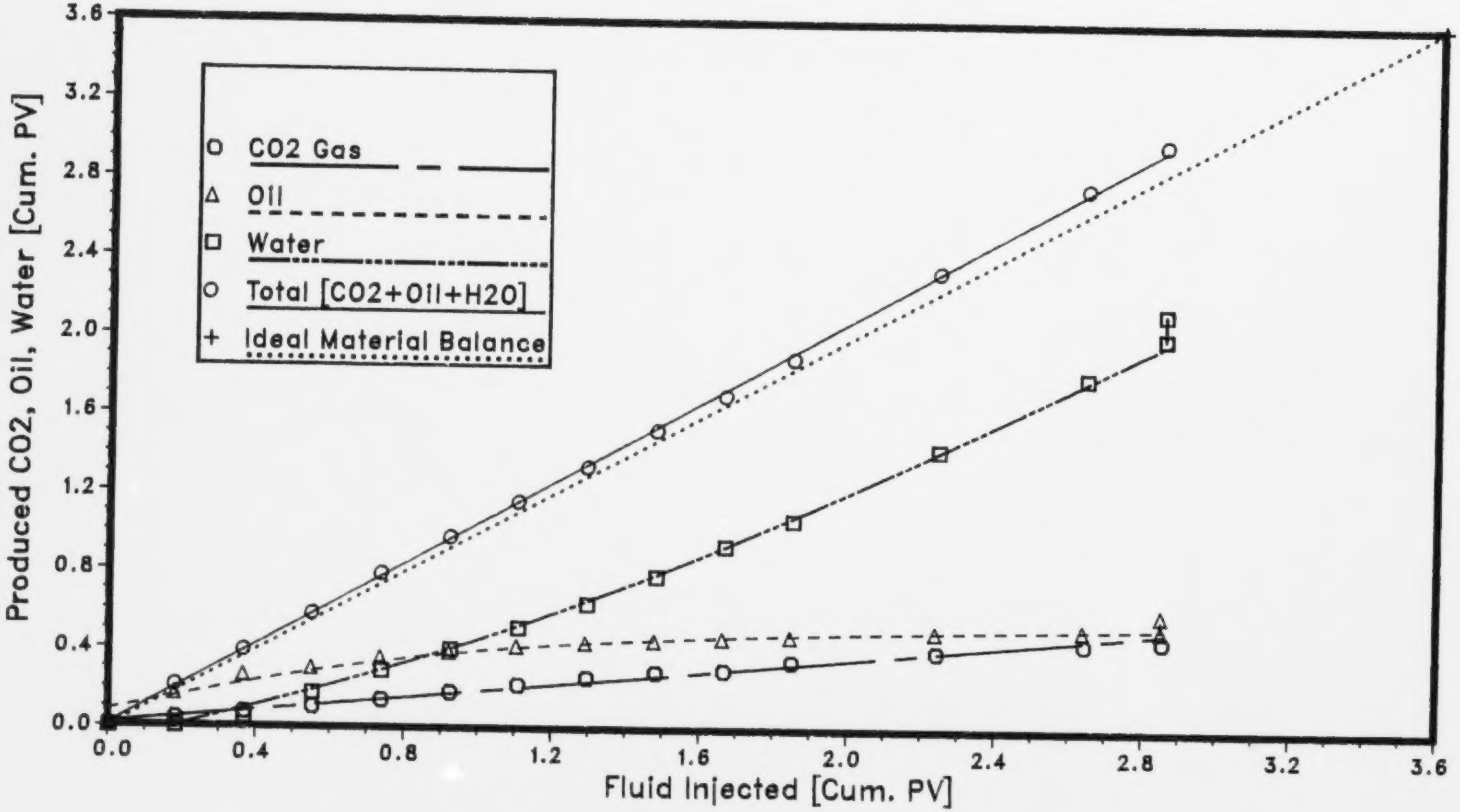
Figure F16: Volumetric Balance on Run LC 36.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s
ϕ = 36.73 %, k = 9.180 darcies, S_o = 88.70 %, S_{wc} = 11.30 %

[0.2 HCPV CO2 @ 1.0 MPa (0.076 g–mol) 4:1 WAG,10 Slugs, LIVE OIL]

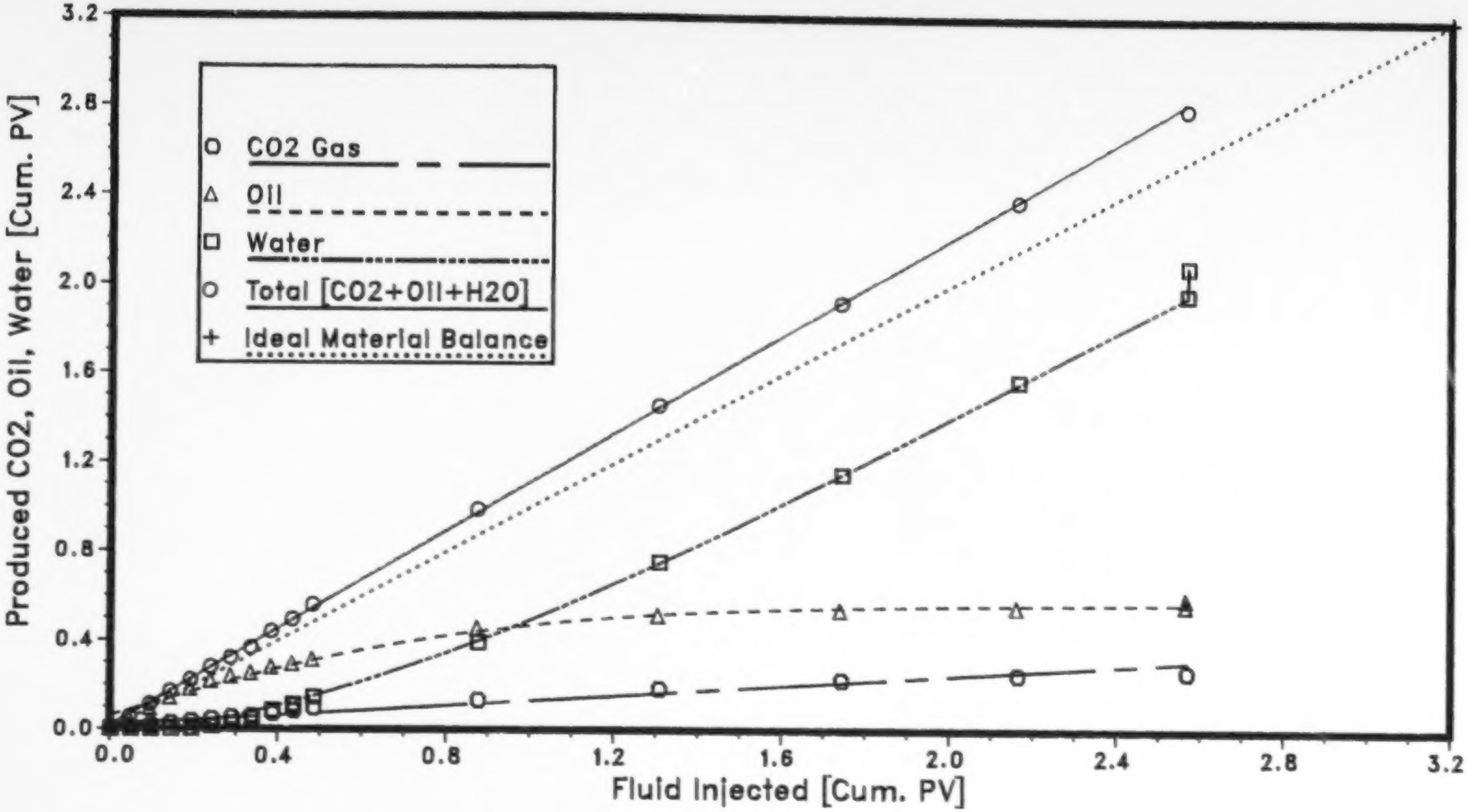
Figure F17: Volumetric Balance on Run LC 37.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s
ϕ = 39.85 %, k = 11.800 darcies, S_o = 90.54 %, S_{wc} = 9.46 %

[0.4 HCPV CO2 @ 1.0 MPa (0.198 g—mol) 4:1 WAG,10 Slugs, LIVE OIL]

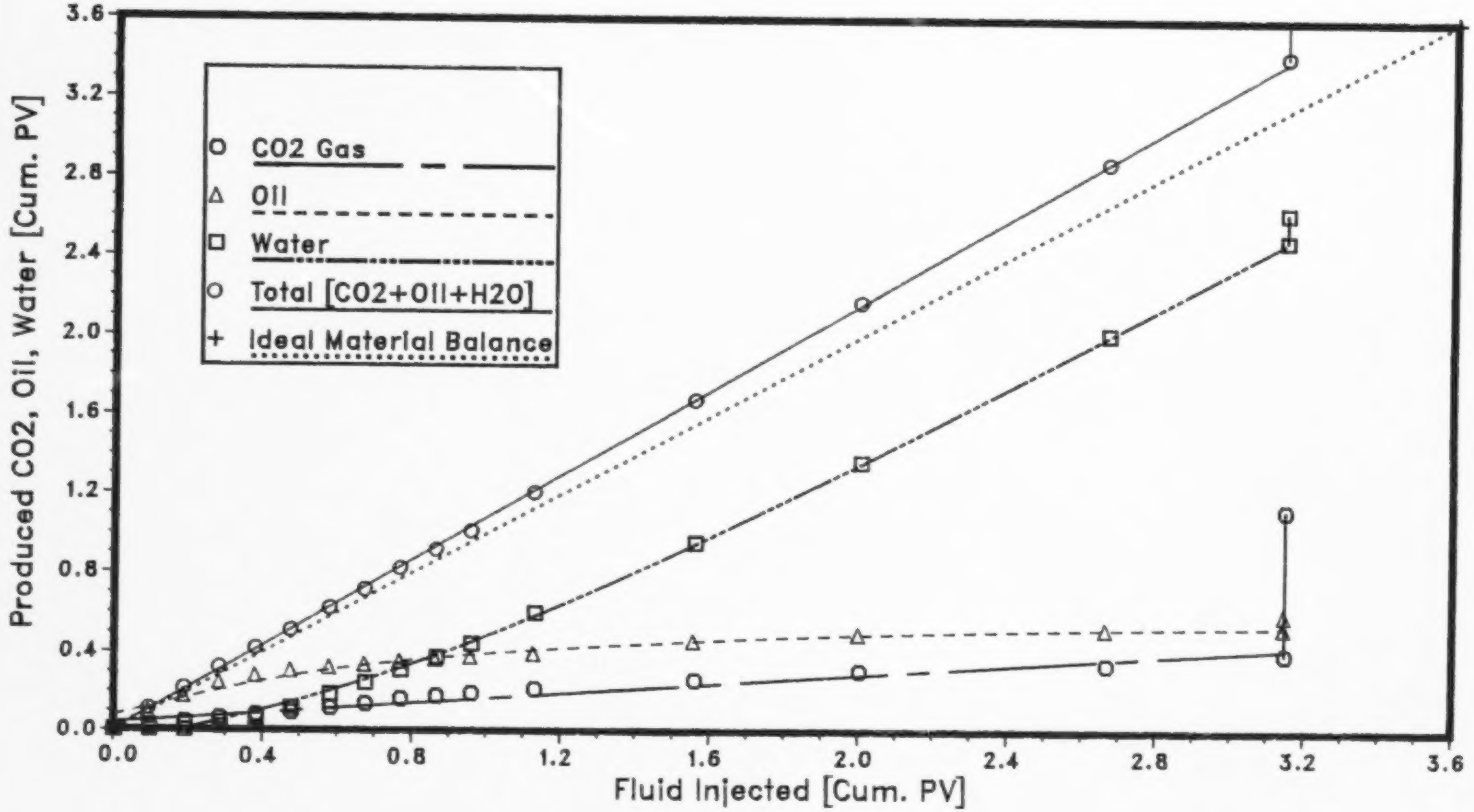
Figure F18: Volumetric Balance on Run LC 38.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s
ϕ = 36.70 %, k = 13.600 darcies, S_o = 95.01 %, S_{wc} = 4.99 %

[0.1 HCPV CO2 @ 1.0 MPa (0.047 g–mol) 4:1 WAG,10 Slugs, LIVE OIL]

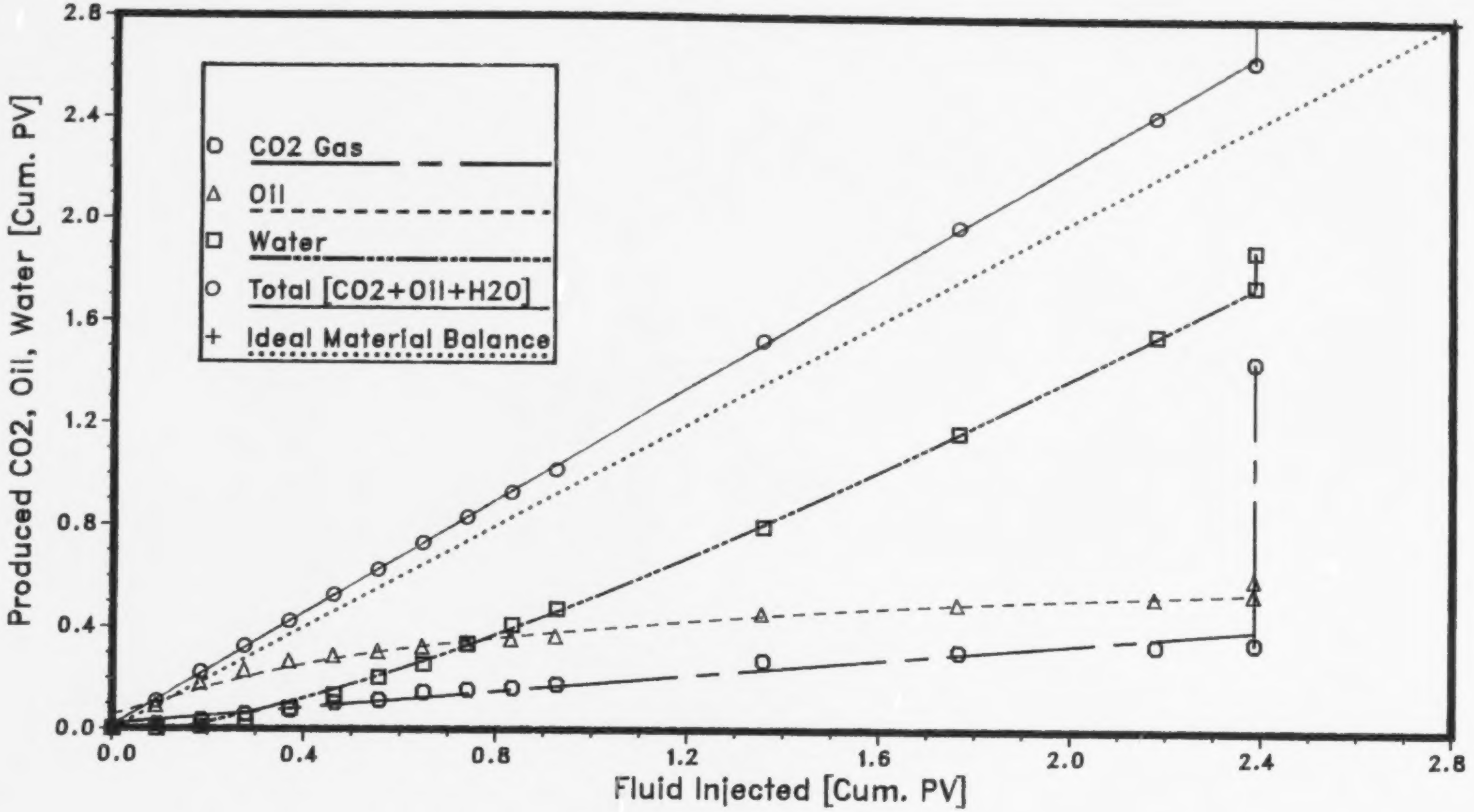
Figure F19: Volumetric Balance on Run LC 39.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s
ϕ = 35.70 %, k = 10.200 darcies, S_o = 94.10 %, S_{wc} = 5.90 %

[0.2 HCPV CO2 @ 1.0 MPa (0.091 g–mol) 4:1 WAG,10 Slugs, LIVE OIL]

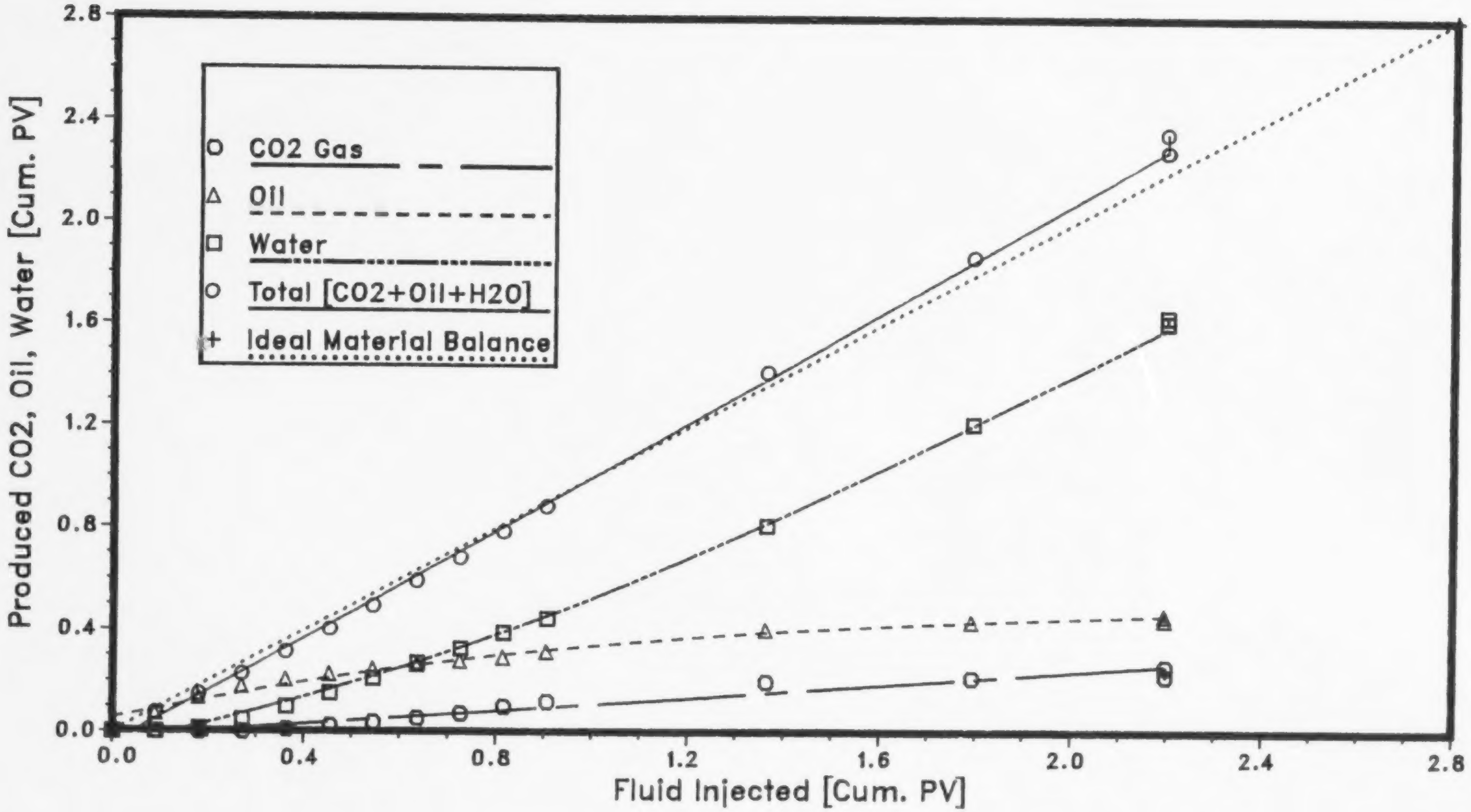
Figure F20: Volumetric Balance on Run LC 40.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s
ϕ = 38.92 %, k = 14.150 darcies, S_o = 92.30 %, S_{wc} = 7.70 %

[0.2 HCPV CO2 @ 1.0 MPa (0.091 g–mol) 4:1 WAG,10 Slugs, LIVE OIL]

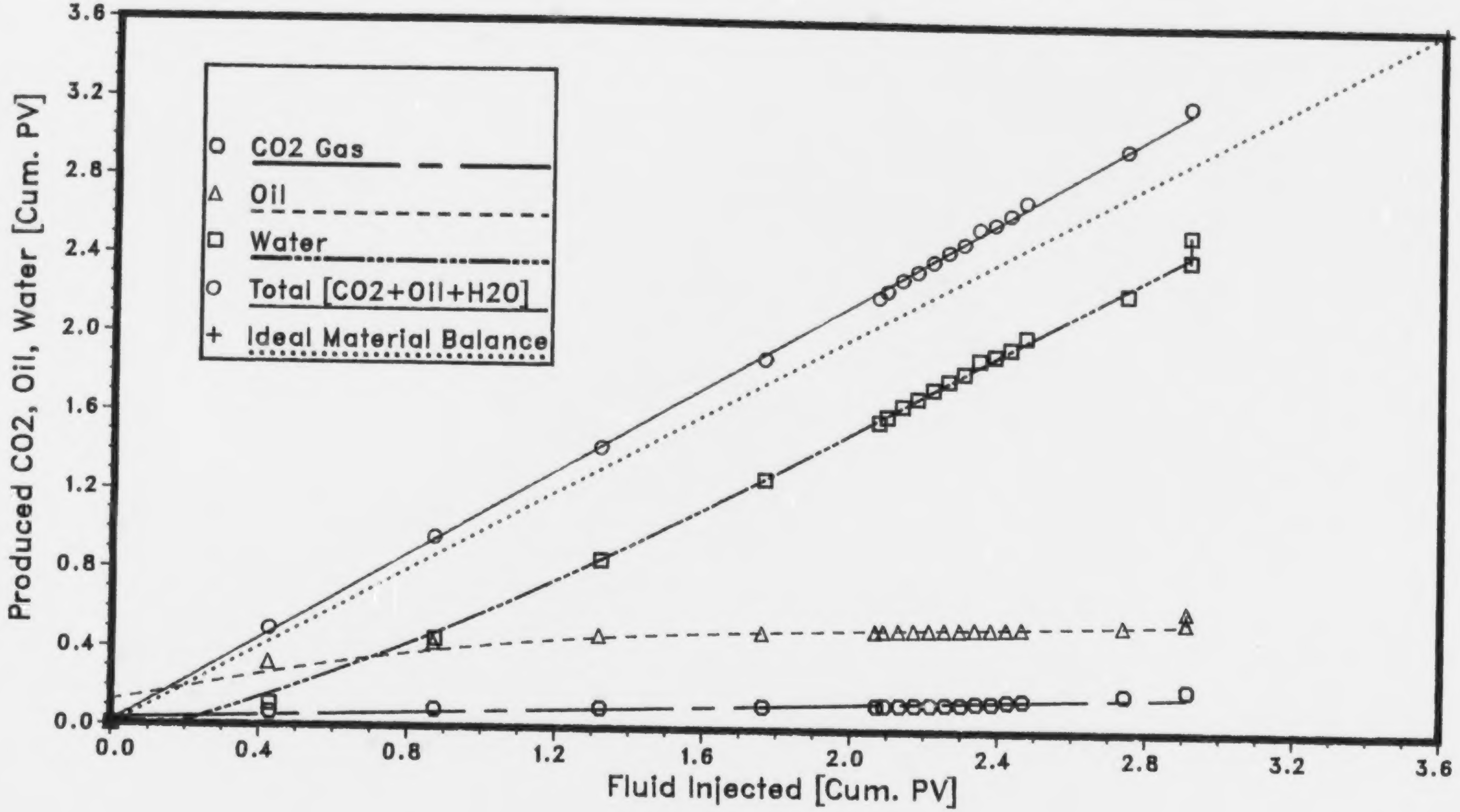
Figure F21: Volumetric Balance on Run LC 41.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s
ϕ = 36.10 %, k = 10.990 darcies, S_o = 90.22 %, S_{wc} = 9.78 %

[0.2 HCPV CO2 @ 1.0 MPa (0.089 g−mol) 4:1 WAG,10 Slugs]

Figure F22: Volumetric Balance on Run LC 42.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s
ϕ = 35.12 %, k = 10.450 darcies, S_o = 92.03 %, S_{wc} = 7.97 %

[2.26 WF => 0.2 RHPV CO2 @ 1.0 MPa (0.039 g–mol) 4:1 WAG, 10 Slugs]

Figure F23: Volumetric Balance on Run LC 43.